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Energy Supply Mitigation Options

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EXECUTIVE SUMMARY

This review focuses on energy supply options that can sharply reduce greenhouse gas (GHG) emissions while providing needed energy services. By the year 2100, the world's commercial energy system will be replaced at least twice, which offers opportunities to change the present energy system in step with the normal timing of the corresponding investments, using emerging technologies in environmentally sound ways. Therefore, this assessment focuses on the performance of these emerging technologies.

Since the preparation of the IPCC 1990 Assessment Report, there have been some significant advances in the understanding of modern technology and technological innovations relating to energy systems that can reduce GHG emissions. Examples of such technologies are found, *inter alia*, in gas turbine technology; coal and biomass gasification technology; production of transportation fuels from biomass; wind energy utilization; electricity generation with photovoltaic and solar thermal electric technologies; approaches to handling intermittent generation of electricity; fuel cells for transportation and power generation; nuclear energy; carbon dioxide (CO_2) sequestering; and hydrogen as a major new energy carrier, produced first from natural gas and later from biomass, coal, and electrolysis.

In the energy supply sector, we conclude with a high degree of confidence that GHG emissions reductions can be achieved through technology options in the following areas (which have been ordered according to type of measure rather than priority):

- **More efficient conversion of fossil fuels**: New technology offers considerably increased conversion efficiencies. For example, the efficiency of power production can be increased from the present world average of about 30% to more than 60% in the longer term. Also, the use of combined heat and power production replacing separate production of power and heat—whether for process heat or space heating—offers a significant rise in fuel conversion efficiency.
- **Switching to low-carbon fossil fuels and suppressing emissions**: Switching from coal to oil or natural gas, and from oil to natural gas, can reduce emissions. Natural gas has the lowest CO_2 emissions per unit of energy of all fossil fuels at ~14 kg/GJ, compared to oil with ~20 kg/GJ and coal with ~25 kg/GJ. The lower carbon-containing fuels can, in general, be converted with higher efficiency than coal. Large resources of natural gas exist in many areas. New, low capital cost, highly efficient, combined-cycle technology has reduced electricity costs considerably in many areas. Natural gas could potentially replace oil in the transportation sector. Approaches exist to reduce emissions of methane from natural gas pipelines and emissions of methane and/or CO_2 from oil and gas wells and coal mines.
- **Decarbonization of flue gases and fuels, and CO_2 storage**: The removal and storage of CO_2 from fossil fuel power-station stack gases is feasible, but reduces the conversion efficiency and significantly increases the production cost of electricity. Another approach to decarbonization uses fossil fuel feedstocks to make hydrogen-rich fuels. Both approaches generate a byproduct stream of CO_2 that could be stored, for example, in depleted natural gas fields. The future availability of conversion technologies such as fuel cells that can efficiently use hydrogen would increase the relative attractiveness of the latter approach. For some longer-term CO_2 storage options, the costs and environmental effects and their efficacy remain largely unknown.
- **Increasing the use of nuclear energy**: Nuclear energy could replace baseload fossil fuel electricity generation in many parts of the world, if generally acceptable responses can be found to concerns such as reactor safety, radioactive-waste transport and disposal, and proliferation.
- **Increasing the use of renewable sources of energy**: Solar, biomass, wind, hydro, and geothermal technologies already are widely used. In 1990, renewable sources of energy contributed about 20% of the world's primary energy consumption, most of it fuelwood and hydropower. Technological advances offer new opportunities and declining costs for energy from these sources. In the longer term, renewable sources of energy could meet a major part of the world's demand for energy. Power systems can easily accommodate limited fractions of intermittent generation, and with the addition of fast-responding backup and storage units, also higher fractions. Where biomass is sustainably regrown and used to displace fossil fuels in energy production, net CO_2 emissions are avoided, as the CO_2 released in energy conversion is again fixed in biomass through photosynthesis. If the development of biomass energy can be carried out in ways that effectively address concerns about other environmental issues and competition with other land uses, biomass could make major contributions in both electricity and fuels markets.

In addition to climate change concerns, there are several concerns of an immediate nature that could be addressed by the energy supply options discussed here (except carbon sequestering); for example, modern renewable sources of energy are often beneficial for local and regional environmental problems (e.g., urban air pollution, indoor air pollution, and acid rain) and for some technologies (especially biomass), rural income and employment generation, and land restoration and preservation. These energy supply options can be pursued to varying degrees within the limits of sustainable development criteria, which may however limit the exploitation of their full technical potential.

A wide range of modular renewable and other emission-reducing technologies are good candidates for cost-cutting through innovation and experience. For such technologies, the cost of the needed research, development, and demonstration (RD&D) and commercialization support is relatively modest (High Confidence).

Some technology options—for example, combined-cycle power generation—would penetrate the current marketplace. To realize other options, governments would have to take integrated action—by improving market efficiency (e.g., by eliminating permanent subsidies for energy), by finding new ways to internalize external costs, by accelerating RD&D on low- and zero-CO_2 emitting technologies, and by providing temporary incentives for early market development for these technologies as they approach commercial readiness. It is concluded with high confidence that the availability, cost, and penetration of technology options will strongly depend on such government action.

To assess the potential impact of combinations of individual measures at the energy system level, in contrast to the level of individual technologies, variants of a low CO_2-emitting energy supply system (LESS) are described. The LESS constructions are "thought experiments" exploring possible global energy systems.

The following assumptions were made: World population grows from 5.3 billion in 1990 to 9.5 billion by 2050 and 10.5 billion by 2100. GDP grows 7-fold by 2050 (5-fold and 14-fold in industrialized and developing countries, respectively) and 24-fold by 2100 (13-fold and 69-fold in industrialized and developing countries, respectively), relative to 1990. Because of emphasis on energy efficiency, primary energy rises much more slowly than GDP. The energy supply constructions were made to meet energy demand in (i) projections developed for the IPCC's First Assessment Report (1990) in a low energy demand variant, where global primary commercial energy use approximately doubles, with no net change for industrialized countries but a 4.4-fold increase for developing countries from 1990 to 2100; and (ii) a higher energy demand variant, based on the IPCC IS92a scenario where energy demand quadruples from 1990 to 2100. The energy demand levels of the LESS constructions are consistent with the energy demand mitigation chapters in this volume.

The analysis of the alternative LESS variants leads to the following conclusions:

- Deep reductions of CO_2 emissions from energy supply systems are technically possible within 50 to 100 years, using alternative strategies.
- Many combinations of the options identified in this assessment could reduce global CO_2 emissions from fossil fuels from about 6 Gt C in 1990 to about 4 Gt C per year by 2050, and to about 2 Gt C per year by 2100. Cumulative CO_2 emissions, from 1990 to 2100, would range from about 450 to about 470 Gt C in the alternative LESS constructions.
- Higher energy efficiency is underscored for achieving deep reductions in CO_2 emissions, for increasing the flexibility of supply-side combinations, and for reducing overall energy system costs.
- Interregional trade in energy grows in the LESS constructions compared to today's levels, expanding sustainable development options for Africa, Latin America, and the Middle East during the next century.

Costs for energy services in each LESS variant relative to costs for conventional energy depend on relative future energy prices, which are uncertain within a wide range, and on the performance and cost characteristics assumed for alternative technologies. However, within the wide range of future energy prices, one or more of the variants would plausibly be capable of providing the demanded energy services at estimated costs that are approximately the same as estimated future costs for current conventional energy. It is not possible to identify a least-cost future energy system for the longer term, as the relative costs of options depend on resource constraints and technological opportunities that are imperfectly known, and on actions by governments and the private sector.

The literature provides strong support for the feasibility of achieving the performance and cost characteristics assumed for energy technologies in the LESS constructions, within the next 1 or 2 decades, although it is impossible to be certain until the research and development is complete and the technologies have been tested in the market. Moreover, these performance and cost characteristics cannot be achieved without a strong and sustained investment in R&D. Many of the technologies being developed would need initial support to enter the market, and to reach sufficient volume to lower costs to become competitive.

Market penetration and continued acceptability of different technologies ultimately depend on their relative cost, performance (including environmental performance), institutional arrangements, and regulations and policies. Because costs vary by location and application, the wide variety of circumstances creates initial opportunities for new technologies to enter the market. Deeper understanding of the opportunities for emissions reductions would require more detailed analysis of promising clusters of options, taking into account local conditions.

Because of the large number of options, there is flexibility as to how the energy supply system could evolve, and paths of energy system development could be influenced by considerations other than climate change, including political, environmental (especially indoor and urban air pollution, acidification, and need for land restoration), and socioeconomic circumstances. Actual strategies for achieving deep reductions might combine elements from alternative LESS constructions. Moreover, there may well be other plausible technological paths that could lead to comparable reductions in emissions. More work is required to provide a comprehensive understanding of the prospects for and implications of alternative global energy supply systems that would lead to deep reductions in CO_2 emissions.

19.1. Introduction

The world energy supply system is huge, and many of the installations have economic lifetimes measured in decades. Annual worldwide investments are on the order of $150 billion. This means that changes will take considerable time to implement. However, within a period of 50–100 years, the entire energy supply system will be replaced at least twice. New investments to replace an old plant or to expand capacity are opportunities to adopt technologies that are more environmentally desirable at low incremental cost. Significant reductions in GHG emissions will not be achieved by a few scattered improvements. New technology must become characteristic for all new investments in order to reduce net carbon emissions significantly. The technologies discussed in this chapter are relevant worldwide and may be introduced more quickly in countries with rapid economic growth than in other countries.

This chapter identifies and assesses energy supply options that can reduce net GHG emissions. However, it does not attempt a comprehensive analysis of all options available for energy system development. There are many ways to reduce emissions. Some are cost-effective now; others will become cost-effective within the next decades; and some options may never be cost-effective, even with massive government support for RD&D and market introduction. Market penetration of different energy sources ultimately depends on the relative costs of fossil and alternative energy forms, as well as other attributes such as abundance, accessibility, institutional arrangements, and regulations and policies that address climate change and other issues. Because costs vary by location and application, the wide variety of circumstances creates initial opportunities for new technologies to enter the market. Deeper understanding of the opportunities for emissions reductions would require more detailed analysis of options, taking into account local conditions. Box 19-1 provides the conventions used throughout this chapter.

19.2. Options to Reduce Greenhouse Gas Emissions

Options to reduce GHG emissions from the energy supply system include improved efficiency in the use of fossil fuels; suppression of GHG emissions; switching to low-carbon fossil fuels; decarbonization of fuels and flue gases, and CO_2 storage and sequestering; and switching to nuclear energy and renewable sources of energy.

19.2.1. More Efficient Conversion of Fossil Fuels to Power and Heat

In this section, technologies for conversion of fossil fuels into heat and electricity—including advanced power-generation technologies, gasification, fuel cells, cogeneration, and the direct use of coal—are discussed.

19.2.1.1. Efficient Power Generation

Large-scale fossil fuel-fired power plants generate power in a steam turbine, a gas turbine, or a combination of the two as a combined cycle. The global average efficiency of fossil-fueled power generation is about 30%, and about 35% in the Organisation for Economic Cooperation and Development (OECD) countries (based on higher heating values, HHV). At a current efficiency of 40%, an increase of 1 percentage point in the efficiency of power generation results in a 2.5% reduction of CO_2 emissions. Figure 19-1 shows the impact of changes in technology and fuels on emissions (Mills *et al.*, 1991). The figure shows that changes in technology can reduce specific emissions by half and changes in fuel by another half, yielding emissions about one-quarter of initial levels.

Environmental and economic concerns have led to major development programs in various countries, in which state-of-the-art, higher-efficiency, combined-cycle, gas-fired stations and coal-fired units operating with supercritical steam cycles have been installed. Such considerations also have led to other major development programs—such as Pressurized Fluidized Bed Combustion (PFBC) and Integrated Gasification Combined Cycles (IGCC) for coal, residual oil, and biomass power generation, which should be commercially available

Box 19-1. Conventions Used

Unless otherwise stated:

Costs are presented in 1990 U.S. dollars and calculated as direct costs on a life-cycle basis, neglecting taxes and assuming a 6% discount rate. Wherever practical, costs are provided for alternative discount rates. Costs for mitigating external effects are included only to the extent required to satisfy existing regulations. There is wide variation in the extent to which external costs have been included in market prices through regulation and/or taxation.

Energy balances are calculated on a life-cycle basis.

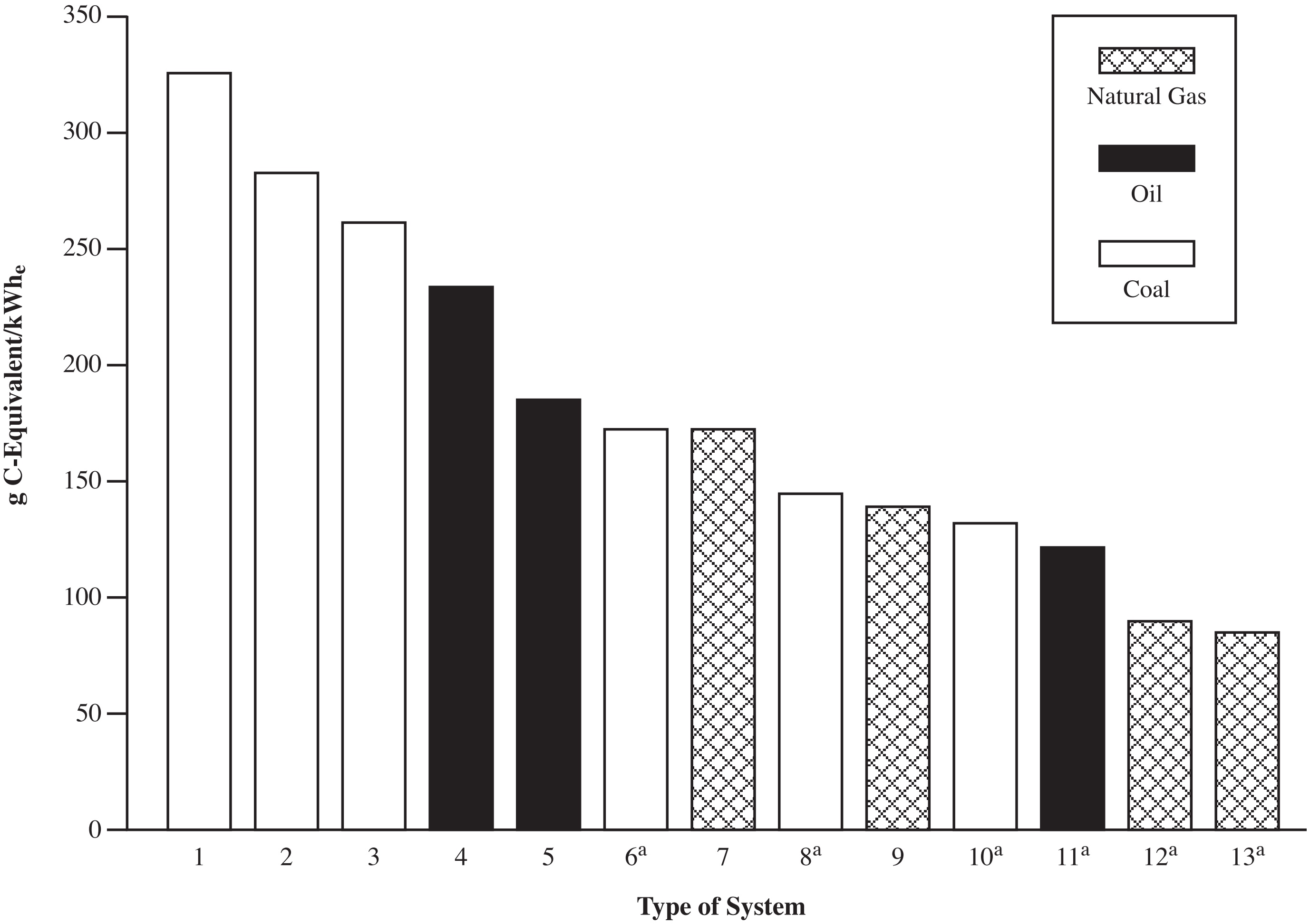
Emissions of greenhouse gases [grams of carbon (C) in CO_2 or grams of methane (CH_4)] refer to emissions at the point of use (direct emissions).

The SI system of **units** is used. Weights also are given in metric tons (t).

Heating values. Energy contents of fuels are based on higher heating values (HHV).

before the year 2010 (Jansson, 1991; Menendez, 1992; Wolk *et al.*, 1991). Characteristics of some of these technologies are indicated in Table 19-1. The information in Table 19-1 was compiled for the year 1992 on a consistent basis; however, recent market transactions suggest capital costs that are significantly lower (by 30% or more), especially for natural gas-fired combined-cycle power plants, leading to lower electricity generation costs.

Considering the situation described above, it would be possible to reduce CO_2 emissions from fossil fuel-fired power plants by 25% or more compared to existing generating technology. This



[a]Cogeneration.
[1]Average conventional steam turbine (coal, 34%).
[2]Best available steam turbine (coal, 39%).
[3]Pressurized fluidized bed combustion (coal, 42%).
[4]Average conventional steam turbine (oil, 38%).
[5]Best available combined-cycle gas turbine (oil, 48%).
[6]Cogeneration: Average conventional steam turbine (coal, 78%, 0.50).
[7]Average combined-cycle gas turbine (natural gas, 36%).
[8]Cogeneration: Best available steam turbine (coal, 83%, 0.60).
[9]Best available combined-cycle gas turbine (natural gas, 45%).
[10]Cogeneration: Pressurized fluidized bed combustion (coal, 86%, 0.65).
[11]Cogeneration: Best available steam turbine (oil, 81%, 0.60).
[12]Cogeneration: Steam-injected gas turbine (natural gas, 75%, 0.80).
[13]Cogeneration: Best available combined-cycle gas turbine (natural gas, 77%, 1.0).

Figure 19-1: Greenhouse gas emissions (in grams of C-equivalent per kWh_e) for commercially available alternative fossil fuels and conversion technologies (adapted from Mills *et al.*, 1991). Central-station power plants are compared with cogeneration plants providing both useful heat and power. The energy requirements for electricity production using cogeneration technologies are taken as the total energy supplied minus that which would have been required to produce the heat independently (assuming a boiler efficiency of 90% on an LHV basis). Parenthetical data in the notes above are fuel, efficiency based on higher heating value in percent, and power-to-heat ratio.

reduction could be achieved with state-of-the-art or near-commercialized technology at little technical risk. Major developments in these areas are being actively pursued in a number of countries.

Further opportunities are provided by advanced gas turbines. Higher turbine inlet temperatures have become possible through the development of new materials and improved cooling systems, offering improved efficiency in power generation. Research efforts are concentrated mainly on improved air cooling of the hot gas path of the turbine; new materials (ceramics, composites, and superalloys); and more efficient air cooling systems (Williams and Larson, 1989).

Advanced cycles, in general, couple a higher-temperature thermodynamic cycle to a lower-temperature cycle to increase efficiency. The most important application is the use of the hot exhaust gases from a gas turbine to raise steam for a steam turbine. Major characteristics of the combined cycle are summarized as follows:

- **High efficiency**: The most efficient units now on the market achieve 52% efficiency (net, generator terminals), and 54–55% is expected in the next few years.
- **Low investment costs**: Approximately 30% less than for a conventional steam power plant
- **Good operating flexibility**: Power generation may be adjusted to demand changes relatively easily.
- **Short installation time**: Operation approximately one year after order, making capacity expansion in small steps possible
- **Low environmental impact**: In particular, very low emission levels of NO_x
- **High power-to-heat ratio in a combined heat and power production**: This means that a larger fraction of the energy is produced as more valuable electricity.

Table 19-1: *Characteristics of some systems for fossil fuel-based power generation under European conditions.*

	Coal		Coal		Coal		Coal		Natural Gas		Natural Gas	
Plant Type	Typical with de-SO_x and de-NO_x		Supercritical with de-SO_x and de-NO_x		IGCC		IGCC with CO_2 Capture		Combined Cycle		Combined Cycle with CO_2 Capture	
Status	Conventional		Established Technology		Demonstration		Available Technology[1]		Established Technology		Available Technology	
Efficiency (%LHV)/ (%HHV)[2,3]	40/38		45(47)/ 43(45)		42(46)/ 40(44)		36/34 [34]		52(55)/ 47(50)		45/41 [44]	
Special Investment Cost ($/kW)[4]	1300		1740		1800		2995		750		1420	
Cost of Electricity (¢/kWh)												
@ Discount Factor (%)	6	10	6	10	6	10	6	10	6	10	6	10
Fuel Price Level A[5]	3.9	4.6	4.1	5.1	4.2	5.2	4.9	6.5	2.4	2.8	4.1	4.9
Fuel Price Level B[6]	4.6	5.3	4.7	5.7	4.8	5.8	5.6	7.2	3.8	4.2	5.8	6.6
Fuel Price Level C[7]	5.0	5.7	5.1	6.1	5.2	6.2	6.1	7.7	4.4	4.8	6.5	7.3
Cost of CO_2 Emission Reduction ($/t C Avoided)[8]	–		–		–		70		–		260	
CO_2 Emission (g C/kWh)	230		200		220		20		110		20	

Sources: Audus and Saroff, 1994; Summerfield *et al*., 1994; Holland *et al*., 1994.
[1] All component parts of the technology are available, but have not been demonstrated at scale in this application.
[2] These are typical values for the power production plant and, where relevant, CO_2 capture and disposal. Figures in brackets are LHV efficiencies on a full fuel-cycle basis.
[3] Higher figures in parentheses are for a well-documented, state-of-the-art advanced plant.
[4] For 500-MW net units in mainland northern Europe (overnight build).
[5] Fuel price level A based on gas at 2.2 US$/GJ and coal at 1.2 US$/GJ.
[6] Fuel price level B based on gas at 4.5 US$/GJ and coal at 2.0 US$/GJ.
[7] Fuel price level C based on gas at 5.5 US$/GJ and coal at 2.5 US$/GJ.
[8] On gas-to-gas and coal-to-coal basis (i.e., not including fuel switching gain of coal to gas), using price level B and 10% discount rate.

Because of such prospects, fossil fuel-based thermal power stations could have efficiencies of around 55% (HHV) on average before the middle of the 21st century.

These advanced cycles require clean gaseous fuels, which has stimulated interest in the production of such fuels from coal and oil.

19.2.1.2. Gasification of Fossil Fuels for Power Generation

Gasification of coal and other heavy fossil fuels may be used, for example, to substitute for natural gas, to produce medium calorific gas, or to produce synthetic gas for chemical production.

Fuel flexibility often is cited as a major advantage of gasifiers. Gasifiers can be either air- or oxygen-blown. In the context of power generation, the relative merits of air- and oxygen-blown systems are far from clear. The penalty for producing the required oxygen from air in an oxygen plant is severe because this consumes about 10% of the power produced. On the other hand, the use of oxygen offers the possibility of CO_2 sequestering and suppresses nitrogen oxides (NO_x) (see Section 19.2.3).

Although there are several proprietary gasifiers on the market that are well established in the chemical industry, they are only at the beginning of their development as far as power generation is concerned. Development programs in progress should ensure that, by the year 2000, IGCC systems will be available. Major gasification development programs are underway in Europe, the United States, and Japan.

To provide a sufficiently clean gas, a wide range of gas treatment processes are available from conventional chemical and gas-processing industries. Many of these clean-up processes are capable of delivering a fuel gas with very low levels of undesirable constituents such as sulfur. IGCC systems, therefore, offer great potential to meet strict air pollutant emission limits.

Maintaining the exit gases from the gasifier at their exit temperature—which is commonly in the range 800–1,000°C—during subsequent cleaning of the gas can contribute significantly to the increased efficiency of IGCC systems. This does not hold for systems in which CO_2 is captured because they are based on shift conversion of the gas CO content to CO_2, and this cannot be done at such high temperatures. Much technical effort is being applied in this area. Examples include the development of high-temperature dust-removal systems such as ceramic filters; dry desulfurization systems, such as zinc oxide-based adsorbents; and solid-based ammonia and alkali metal-removal systems. All of these systems have yet to be demonstrated on a significant scale, although recent PFBC work with demonstration-scale hot gas filters has been done in Sweden.

19.2.1.3. Fuel Cells for Power Generation

Fuel cells convert chemical energy into electricity without first burning the fuel to produce heat. Fuel cell power systems are characterized by high thermodynamic efficiency and low levels of pollutant emissions. Almost all fuel cells currently developed for commercialization use pure hydrogen as the fuel. Generally this implies that a primary fuel—for example, coal, natural gas, or biomass—first has to be converted to a hydrogen-rich gas. Fuel-cell systems offer the possibility of small-scale as well as large-scale electricity production at a conversion efficiency from hydrogen ranging from 40–70% (LHV) and more than 80% in cogeneration (de Beer and Nieuwlaar, 1991). Different types of fuel cells are currently being investigated: the alkaline fuel cell (AFC), phosphoric acid fuel cell (PAFC), molten carbonate fuel cell (MCFC), solid oxide fuel cell (SOFC), and solid polymer electrolyte fuel cell (SPEFC) (for an overview, see de Beer and Nieuwlaar, 1991).

Much attention is being given to the development of fuel cells for large-scale power production (more than 200 MW_e), integrating fuel cells with steam turbines or gas turbines. Key uncertainties are the limited fuel-cell lifetime and the relatively high cost of the high-temperature fuel-cell systems. The environmental performance of these systems probably is not much better than the performance of conventional power generation with additional cleaning technologies. Therefore, fuel-cell plants for large-scale power production will have severe competition from advanced IGCC and natural gas, combined-cycle power plants. This situation might change, however, when power production is combined with CO_2 removal; a combined coal-gasifier/fuel-cell system facilitates such removal (Jansen *et al*., 1994).

Small-scale combined heat and power (CHP) production is the first market segment in which significant market penetration of fuel cell systems is expected. Widespread use would reduce the emission of pollutants significantly.

In the longer term, one can envisage centralized energy systems in which fossil fuels are converted and separated into hydrogen and CO_2 (or carbon black). The latter could be stored; the former piped and utilized for a variety of applications. Low-temperature fuel cells—such as AFC, SPEFC, and PAFC—are especially well-suited for such configurations. Potential markets are CHP in residential and commercial buildings that need low-temperature heat (Ingersoll, 1991; A.D. Little, 1995; Dunnison and Wilson, 1994), as well as transportation applications (see Section 19.2.6.4).

19.2.1.4. Combined Heat and Power Production

CHP production offers a significant rise in fuel efficiency and therefore is of interest in connection with GHG mitigation. CHP has applications in the industrial, residential, and commercial sectors (IEA, 1993a).

Combined production of heat and electricity is possible with all heat machines and fuels (including biomass and solar thermal) from a few kW-rated to large steam-condensing power plants. Heat-plus-power (first-law) efficiencies are typically 80–90%. CHP plants may have an added heat storage that allows the production plant to operate at optimum economy while still covering heat needs. Table 19-2 lists four typical examples of

Table 19-2: *Energy balance and C emissions of CHP plants and separate power and heat production.*

Power and Heat Plant Technology	Energy Balance (GJ) Fuel Input[1]	Power/Heat Output	Fuel Reduction by Introducing CHP	CO_2 Emissions t C	Reduction by Introducing CHP[2]
Large Coal-Fired CHP Plant	100	36/56		2.4	
Large Coal-Fired Power Plant plus Residential Gas Burner	80/59	36/56	28%	2.7	11%
Large Coal-Fired Power Plant plus Residential Coal Burner	80/112	36/56	48%	3.5	31%
Small Biomass-Fueled CHP Plant	100	22/56		0	
Large Coal-Fired Power Plant plus Residential Gas Burner	49/59	22/56	7%	2.0	100%
Small Gas Turbine CHP Plant	100	30/55		1.4	
Large Coal-Fired Power Plant plus Residential Gas Burner	60/58	30/55	15%	2.2	37%
Medium-Sized Gas Engine CHP Plant	100	39/46		1.4	
Large Coal-Fired Power Plant plus Residential Gas Burner	78/48	39/46	21%	2.5	45%

[1]Arbitrarily fixed reference level.
[2]Some of the percentage reductions show the combined effect of CHP and fuel switching.

CHP installations of various sizes, their power and heat production, and reductions in fuel use and CO_2 emissions relative to appropriate alternatives for separate supply of heat and power (Olsen, 1993). Combined-cycle power and heat production provides better thermodynamic performance than single cycles, even if first-law efficiencies are lower, because more electricity is produced. This electricity may in principle be used with heat pumps to generate more heat at a higher temperature.

The employment of CHP is closely linked with the availability or development of district heating (DH) and/or cooling networks and building heat and/or cooling distribution systems, as well as industrial heat loads. DH networks are energy transmission systems suited for the distribution of heat and/or cooling within areas with sufficiently high heat/cooling load densities (Kalkum *et al*., 1993; Rogner, 1993). Modern water-based heating and/or cooling transmission and distribution systems for cities have low losses, typically 10–15% (WEC, 1991).

A prerequisite for DH is central heating systems in buildings. These are customary in most temperate and some subtropical regions. Central heating is most easily achieved if considered at the planning stage, along with electricity, water and sewage, telephone, and optical fiber lines.

Today, widespread coverage by CHP exists in Denmark and Finland (WEC, 1991; Danish Energy Agency, 1993), and substantial DH exists in Austria, Germany, the Netherlands, Poland, Russia, Sweden, and other countries.

Fossil fuels, industrial wastes, and waste heat from processes are used widely in process industries to generate power and heat. The pulp and paper industry is the largest user of biomass energy through combustion of waste liquors and other wood waste. CHP has been utilized in other industries, but to much lesser extent. Now the situation is changing because of regulatory changes (like the Public Utilities Regulatory Policy Act in the United States) and the good economy of cogeneration. Industrial heat demand often has some special characteristics, such as large and fast load variations, intermittent need for heat and power (mechanical work), and extractions of heat (as steam) at different temperature and pressure levels. Otherwise, CHP technology is very similar to that in DH except for the use of special process and waste-heat boilers, where corrosion may limit the attainable pressure and temperature levels (Saviharju, 1995). Compared with DH plants, the temperature levels of the extracted heat are higher, which results in much lower power yields (lower power-to-heat ratio). These may be enhanced considerably, however, through the use of combined-cycle technology, including IGCC technology. The heat distribution system may serve a single mill or a whole industrial city, ranging to hundreds of MW of heat.

19.2.1.5. Direct Coal Use in Developing Countries and Economies in Transition

Developing countries and economies in transition burn coal directly as fuel for cooking and space heating and fuel for small industries. For example, the direct use of coal accounts for about two-thirds of the coal used in China. Typically, conversion efficiencies are low for these applications, and—because of coal's high content of ash, sulfur, and other pollutants—direct coal use is a major source of local and regional air pollution. A substantial reduction in emissions, including CO_2, can be achieved by using coal in more efficient appliances or by converting coal into a synthetic fuel (or electricity and district heat) before distribution to final users.

Coal conversion to cleaner fuels—for example, town gas—essentially eliminates sulfur and particulate emissions at the point of end-use. Such upstream conversion of coal, however, is capital-intensive, incurs conversion losses, and requires grid distribution systems. Because of capital limitations, the direct use of coal will remain important in many countries for decades (Sun and Li, 1992). Transferring efficient residential and industrial coal appliances to developing countries is as important as transferring coal-cleaning equipment, power generation plants, and other central conversion plants and equipment (Pachauri, 1993; Topper, 1993; Graham-Bryce *et al.*, 1993; Ramakrishnan, 1993; Su and Gu, 1993).

19.2.2. Suppression of GHG Emissions and Fuel Switching

Suppression of CO_2 and methane (CH_4) emissions and switching to low-carbon fuels—for example, from coal to oil and gas, which is a shift to fuels with a lower carbon to hydrogen ratio—offer significant potential for reducing GHG emissions.

19.2.2.1. Suppression of Methane Emissions

Total CH_4 emissions are estimated at 560 ± 90 Mt/yr, of which 70% is from anthropogenic sources and 30% from natural sources (Lelieveld and Crutzen, 1993; IPCC, 1992). About 30% of the anthropogenic sources may be associated with the use of fossil fuels.

CH_4 emissions from coal mining and natural-gas venting, as well as leakage from pipeline and distribution systems, are significant. It has been estimated that the coal industry worldwide contributes 4–6% of global methane emissions (CIAB, 1992). Flaring and venting has been estimated to be about 5% of world natural-gas production (Barn and Edmonds, 1990; U.S. EPA, 1993a). Available technology can reduce emissions from coal mining by 30–90%, from venting and flaring by more than 50%, and from natural-gas distribution systems by up to 80% (U.S. EPA, 1993a). Options for limiting emissions from coal mining; natural-gas production, transmission, and distribution; and landfills (see Chapter 22) may be economically viable in many regions of the world, providing a range of benefits—including the use of CH_4 as an energy source (U.S. EPA, 1990a, 1990b, 1993a, 1993b; Blok and de Jager, 1993).

There are many options for suppressing emissions from the oil and natural gas industries, including capturing and using or recompressing residuals and purged gas, improving gas leakage-detection methods, applying pneumatic devices to control or eliminate venting, repairing or replacing pipelines, and using automatic shutoff valves (U.S. EPA, 1993a). Some of these measures are capital-intensive and could be difficult to carry out in some regions, due to specific geographical as well as economic conditions. Flaring is preferable to venting from a GHG point of view because a molecule of CH_4 leads to a much larger radiative forcing in the atmosphere than a molecule of CO_2.

CH_4 emissions from coal mining depend on several factors, but emissions from underground mines are one order of magnitude higher than from surface mines (Smith and Sloss, 1992). Only emissions from underground mines can be reduced *before* (predegasification), *during* (recovery of ventilation air), and *after* (gob-well recovery, from the highly fractured area of coal and rock that is created by caving in of the mine after mining has been completed) the mining of the coal (U.S. EPA, 1993a). Whereas premining and postmining degasification has been widely applied in many countries, it is not suitable for every coal deposit. The economic feasibility of CH_4 recovery from ventilation air has not yet been demonstrated, although technology is available. In optimal conditions, the combination of these three options—"integrated recovery"—can achieve an emissions reduction of up to 80–90% (Blok and de Jager, 1993; U.S. EPA, 1993a).

19.2.2.2. Flaring of Natural Gas and Alternatives to Flaring

An estimated average of 0.5% or more of natural-gas production is emitted into the atmosphere from upstream oil and gas operations (U.S. EPA, 1990b). In some areas, emissions are assumed to be as high as 15%, of which 6% is emitted from natural-gas use. Such high levels of emissions probably will decrease within 20 to 50 years (Picard *et al*, 1992). Also, many oil production facilities either produce very small amounts of gas in association with oil (after satisfying on-site fuel requirements) or are too far from gas-collecting systems for feasible conservation or reinjection of the gas. Therefore, gas usually is vented or flared if it is uncollected. Options for disposing of or utilizing waste gas at oil production facilities include small-scale on-site power generation, cogeneration, and transport fuel production. These options could reduce emissions by 50–99% (Picard and Sarkar, 1993). The largest reductions of gas venting and flaring from oil and associated gas facilities would result from making these activities economically attractive.

Natural gas is flared to prevent natural gas explosions in the air, to ensure continuous flow, and to keep production smooth in the downstream facilities. Options to reduce the volumes flared in continuous gas flows include using nitrogen as a purge gas and recovery of low-pressure gas. Gas flaring caused by faults in processing could be reduced by improving maintenance. Improving system reliability and storage capacity may reduce emissions of excess gas flared when demand is low. These options vary according to the location and characteristics of the oil industry.

19.2.2.3. Suppression of CO_2 from Natural Gas and Oil Wells

The CO_2 content in natural gas fields or oil wells varies, which significantly affects life-cycle CO_2 emissions. Depending on the ratio of CH_4 to other gases, the extraction and use of natural gas leads to CO_2 emissions of less than 14 kg C/GJ of natural gas (HHV) if the CO_2 content of the natural gas field is less than about 1%. Most fields exploited presently are in this range (Schroder and Schneich, 1986)—for example, the Groningen field in The Netherlands, which contains 0.89% CO_2 (Blok *et al*., 1989). However, there are also natural gas fields with a much higher CO_2 content. For example, the Krahnberg field in Germany contains 53.4% CO_2 and the Catania field in Italy 48.8% CO_2. Although not yet developed due to high CO_2 content, the Natuna field in Indonesia contains more than 70% CO_2.

Exploitation of such fields requires removal of CO_2 to meet transport and sales specifications, typically less than 2–3%. Ordinarily the CO_2 is emitted to the atmosphere. In the case of the Sleipner Vest field (9.5% CO_2) in Norway, however, the CO_2 removed will be injected into an aquifer at 1,000 m below the main Sleipner platform. Approximately 1 Mt/yr CO_2 (~0.25 Mt/yr of carbon) will be removed from a 100-bar natural gas stream, which is costly but uses well-known technology. The decision to store the CO_2 was stimulated by the introduction of a carbon tax of about $180/t C in Norway (Kaarstad, 1992).

19.2.2.4. Fuel Switching

Switching from coal to oil or natural gas would reduce carbon emissions in proportion to the carbon intensity of the fuel. For example, switching from coal to natural gas would reduce emissions by 40% (see Box B-2 in Chapter B). In addition, the higher energy efficiency achievable with natural gas would reduce emissions further—for example, a shift from coal to natural gas in power generation by 20%.

19.2.3. Decarbonization of Fuels and Flue Gases, CO_2 Storage, and Sequestering

In the longer term, decarbonization would allow continued large-scale use of fossil fuels. Here, decarbonization implies utilization of the energy in carbon with greatly reduced CO_2 emissions. This can be done practically only in large-scale energy conversion facilities. It is logical, therefore, to begin decarbonization efforts in large fossil fuel-burning power stations, which at present account for a quarter of total CO_2 emissions from fossil fuels. Either CO_2 can be captured from flue gases or carbon-containing fuels can be converted to low-carbon, hydrogen-rich fuels before utilizing them (Pearce *et al*., 1981; Blok *et al*., 1991, 1992; U.S. DOE, 1993).

If deep CO_2 emission reductions are desired, it would be necessary to extend the effort beyond power generation. This is problematic, however, because most fuels used directly are consumed in small-scale conversion systems in which decarbonization is not practical. This problem might be solved by converting the fossil fuel to a low-carbon, hydrogen-rich fuel or to a carbon-free fuel (essentially hydrogen) and CO_2 in a centralized facility, followed by removal of the CO_2 and distribution of the low-carbon or carbon-free fuel to the consumer (Marchetti, 1989; Blok *et al*., 1995; Williams, 1996).

In either case—flue gas decarbonization or fuel decarbonization—the captured CO_2 has to be utilized, stored, or isolated from the atmosphere in an environmentally acceptable manner.

19.2.3.1. Decarbonization of Flue Gases

The capture of CO_2 from the flue gases of fossil fuel-fired power plants and its subsequent use or disposal is being actively investigated in a number of countries (Blok *et al*., 1992; Riemer, 1993; U.S. DOE, 1993; Herzog and Drake, 1993; Aresta *et al*., 1993; Kondo *et al*., 1995). Interest in the capture of CO_2 from power plant flue gases started before it was seen as a GHG mitigation option. The driving force was the desire for an inexpensive, readily available source of CO_2 to use in enhanced oil recovery (EOR). Three such plants were built in the United States to provide CO_2 for EOR using natural gas as a primary fuel. Another plant, still in operation, uses coal as a source of CO_2 for the production of soda ash. All of these plants have applied well-established technology to capture the CO_2 from the flue gases.

The use of these technologies incurs a cost and energy penalty. Starting with a conventional coal-fired power plant of 600 MW_e and a coal-to-busbar conversion efficiency of, for example, 41% (LHV), the efficiency might decrease to, for example, 30% if the CO_2 emission is reduced from 230 gC/kWh to about 30 gC/kWh in the modified plant. The costs of electricity production would then increase by about 80%, which is equivalent to $150/t C avoided. Starting with a natural gas-fired, combined-cycle plant of 600 MW_e and a conversion efficiency of 52% (LHV), the efficiency might decrease to 45% if the CO_2 emission is reduced from 110 gC/kWh to about 20 gC/kWh in the modified plant. In this case, the costs of electricity production would increase by about 50%, which is equivalent to $210/t C avoided. R&D efforts are focused on minimizing these penalties (Blok *et al*., 1992; U.S. DOE, 1993; Herzog and Drake, 1993; Hendriks *et al.*, 1993; Kondo *et al.*, 1995). One option under investigation to reduce costs is the use of oxygen rather than air for combustion to obtain a flue gas that is essentially CO_2. For a coal-fired power station, the removal costs might then be less than \$80/t C avoided (Hendriks, 1994).

19.2.3.2. Decarbonization of Fuels

One frequently suggested scheme for decarbonization of fuels is the development of an IGCC power plant with CO_2 removal. In this scheme, the gasifier off-gas is converted with steam to CO_2 and hydrogen (via $H_2O + CO \longrightarrow CO_2 + H_2$) and then separated to make a fuel gas stream that is essentially hydrogen. Due to its high partial pressure, the CO_2 can be recovered by using a physical solvent for which regeneration requires only a release of pressure. After separation, the hydrogen-rich fuel is burned in a combined cycle to generate electricity. The CO_2 emission factor of the fuel would be smaller than 4 kgC/GJ, compared with 24 kgC/GJ for coal. Starting from an original IGCC plant with a coal-to-electricity efficiency of about 44% (LHV), this efficiency might decrease to about 37%, with the CO_2 emissions reduced from approximately 200 gC/kWh to less than 25 gC/kWh. Due to the recovery, the costs of electricity production might increase by 30–40%. The removal costs would then be less than \$80/t C avoided (Hendriks *et al*, 1993; Hendriks, 1994). These penalties might be reduced substantially if the gasification of coal and the recovery of CO_2 were integrated with the use of fuel cells to generate electricity. Such a configuration could result in a higher conversion efficiency (42–47%, LHV) (Jansen *et al.*, 1992).

The hydrogen-rich fuel also can be used for applications other than power generation, although doing so requires further purification of the fuel (Watson, 1983; Blok, 1991) and the build-up of a corresponding infrastructure (see Section 19.2.6).

Due to the increased costs of the hydrogen fuel compared to the original feedstock, some experts have concluded that decarbonization processes are inherently expensive. For the recovery of CO_2 by steam reforming of natural gas, they calculate costs ranging from \$210 to \$460/t C recovered (Kagoja *et al.*, 1993). It has been suggested that hydrogen has a greater value than the feedstock from which it is produced because it allows the use of more efficient conversion technologies. The costs of decarbonizing fuels therefore must be assessed at the systems level. For example, the production of hydrogen from natural gas or coal and its use in a fuel-cell vehicle typically would lead to lower primary energy consumption than if gasoline derived from crude oil were used in a comparable vehicle (see Section 19.2.6.4). At present, the least costly way to produce hydrogen often involves the use of natural gas as the feedstock; in the process, a stream of pure CO_2 is produced as a byproduct. If this CO_2 could be captured and stored in a nearby exhausted natural-gas field, the costs of avoiding the CO_2 emissions are estimated to be less than \$30/t C (Farla *et al.*, 1992). The net costs could be even less (and possibly close to zero) if possibilities for modest enhanced natural gas recovery as a result of reservoir repressurization by the CO_2 were exploited (Blok *et al.*, 1995).

Carbonaceous materials (fossil fuel, biomass, waste, etc.) also could be converted into chemically stable carbon and hydrogen or hydrogen-rich methanol (Steinberg, 1991). As a result, carbon could be stored instead of CO_2. Although theoretically possible, this approach is very difficult practically.

19.2.3.3. Storage of CO_2

The technology to capture CO_2 is available, but to have an impact on GHG emissions, credible and environmentally acceptable utilization, storage, and/or disposal options are required. Because of the small potential for utilization (Aresta *et al.*, 1993; Herzog and Drake, 1993), several possibilities for underground storage or ocean disposal of CO_2 are being investigated. An overview of storage options is presented in Table 19-3, together with an indication of their potential capacities based on low estimates in the literature. Enhanced oil recovery (EOR) using CO_2 as a miscible flooding agent has a high potential. The CO_2 is partly stored during the recovery of the oil. At present oil price levels, however, the application of CO_2 in EOR is not profitable unless there is access to CO_2 from a cheap source, such as a natural underground source. Examples can be found in the United States, where CO_2 from natural sources is transported hundreds of kilometers by pipeline for EOR use. For a typical case, total pipeline transportation cost of CO_2 is about \$8/t C for a 250-km, 750-mm pipeline for 5.5 Mt C of CO_2 per year (Skovholt, 1993). EOR using CO_2 from power plants might reduce the annual anthropogenic CO_2 emissions by about 1% (Taber, 1993).

Storage in exhausted oil and gas wells is a viable option. The capacity of natural-gas fields to sequester carbon at the original reservoir pressure is generally greater than the carbon content of the original natural gas. As a worldwide average, about twice as much carbon can be stored as CO_2 in depleted reservoirs as was in the original natural gas (Hendriks, 1994). The estimated storage capacity ranges from about 130 Gt C to 500 Gt C, based on different views of recoverable oil and gas. The cost of CO_2 storage in onshore natural-gas fields is estimated to be less than \$11/t C (Hendriks, 1994).

Table 19-3: *Low estimates of CO_2 storage potentials.*

Option	**Potential Global CO_2 Storage Capacity (Gt C)**
Enhanced Oil Recovery	>20
Exhausted Gas Wells	>90
Exhausted Oil Wells	>40
Saline Aquifers	>90
Ocean Disposal	>1200

Another option is storage in saline aquifers (i.e., permeable beds, mostly sandstone), which can be found at different depths all over the world. First estimates of their storage capacity range from about 90 to about 2,500 Gt C, due to different assumptions about the volume of aquifers, the percentage of the reservoir to be filled, the density of CO_2 under reservoir conditions, and the area suitable for CO_2 storage (Riemer, 1993; Hendriks *et al*., 1993). Depending on the availability of compressed CO_2—for example, from an IGCC plant with CO_2 removal—and other local circumstances, the costs of underground storage onshore might vary from about \$7 to \$30/t C, transportation costs excluded (Hendriks, 1994). CO_2 storage in aquifers has safety risks and environmental implications. Potential problems include CO_2 escape, dissolution of host rock, sterilization of mineral resources, and effects on groundwater (Riemer, 1993; Hendriks *et al*., 1993).

The deep ocean is the largest potential repository for CO_2. The oceans contain about 38,000 Gt C and will eventually absorb, after equilibration, perhaps 85% of the CO_2 that is released to the atmosphere from energy conversion processes (Houghton *et al*., 1990). CO_2 could be transferred directly to the oceans, ideally at a depth of perhaps 3,000 m—from where it would take at least several hundred years before it partly escaped to the atmosphere. Concern over potential environmental impacts, the practical limitations on pipeline depth, and the assurance of adequate retention time suggest that injection at 1,000 m at carefully selected sites could be a realistic option. Costs are probably marginally higher than for subterranean disposal (U.S. DOE, 1993), but—as with most options—the cost of transporting CO_2 to the disposal site often dominates.

Not much is known about the environmental effects of storing CO_2 in the oceans—for example, the impacts on marine life, either directly (as discussed here) or indirectly (via the atmosphere). Preliminary studies indicate that ecological perturbations would be confined to the release area, which would be a small percentage of the whole ocean volume (U.S. DOE, 1993). A maximum deviation of 0.2 pH units for coastal waters has been recommended (U.S. EPA, 1976). This would correspond to a buffer capacity of 1,200 Gt C (Spencer, 1993). These aspects need further research.

19.2.3.4. CO_2 Sequestering

Reforestation with the application of forest management techniques provides a method of offsetting CO_2 emissions (Maclaren *et al*., 1993; see also Chapter 24). Carbon is captured and stored during the growth time of a forest and would need to be stored for a long time thereafter. Costs are \$12–30/t C, assuming a land value of about \$800/ha in industrialized countries and about \$300/ha in developing countries (Huotari *et al*., 1993). Other studies indicate costs as low as \$3.5/t C (Face Foundation, 1995). At high levels of reforestation, costs can be expected to increase.

Offsetting carbon emissions from a 500 MW_e coal-fired power station (emitting about 0.8 Mt C/yr) by growing a forest on unforested land would require an area of at least 1,700 km^2, on the basis of a productivity of 2–4 tons/ha/yr during 50 years and a storage of 100–200 tons of carbon per hectare in a mature forest.

Growing biomass for energy as a fossil fuel substitute is an alternative to growing biomass for sequestering carbon. The preferred strategy depends on various factors, including the current status of the land and the biomass yields that can be expected. For forests with large standing biomass, the most effective strategy is to protect the existing forest; for land with little standing biomass and low yields, the most effective strategy is to reforest the land for carbon storage. Where high yields can be expected and markets for the biomass are readily accessible, however, often the most effective strategy is to manage the forest as a harvestable energy crop for fossil fuel substitution (Hall *et al*., 1991; Marland and Marland, 1992).

19.2.4. Switching to Nuclear Energy[1]

In 1992, nuclear power generation totaled 2,030 TWh—about 17% of all electricity or more than 5% of commercial energy consumption worldwide (all statistical data on nuclear power quoted in this section are from IAEA, 1995a; OECD/NEA, 1993). The operational experience of electricity-generating nuclear power plants of all sizes exceeds 6,500 reactor-years. At the beginning of 1993, there were about 425 nuclear power reactors connected to electricity supply networks, with a total installed capacity of about 331 GW_e. More than 30 countries have nuclear power plants in operation or under construction.

If the entire upstream and downstream energy chains for electricity generation are included, nuclear power CO_2 equivalent emissions are 1/10 to 1/100 those of fossil fuel plants. The range depends on assumptions about the competing fossil fuel technology and on the uranium content of ores, the uranium enrichment technology, and the management of radioactive waste (The Netherlands Ministry of Economic Affairs, 1993; Uchiyama and Yamamoto, 1991). Nuclear plants producing electricity reduce CO_2 emissions from the energy sector by about 7% compared to the present world mix of fossil fuel-based power generation (Van de Vate, 1993).

For nuclear energy to play a major role in future GHG mitigation, a considerable expansion must take place. Historically, nuclear power expanded rapidly. Construction starts per year reached a peak in the late 1960s but declined by 90% during the last 6–7 years (see Figure 19-2). Grid connections peaked in the mid-1980s at more than 30 GW/yr and then decreased to a few GW/yr. For nuclear energy to assume an increased role in reducing GHG emissions, growth has to be resumed. It is therefore necessary to analyze the reasons behind the developments summarized in Figure 19-2 and to understand the issues that must be addressed for a revival of the nuclear option.

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[1] A supporting document exists for this section (see IAEA/OECD, 1995).

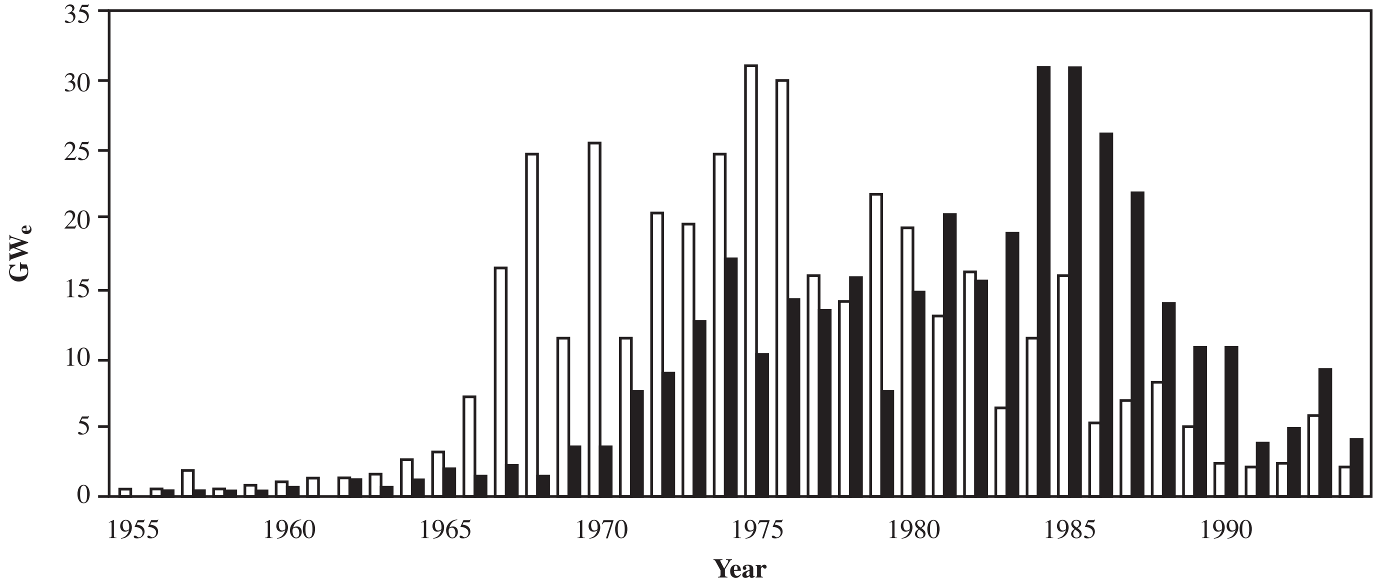


Figure 19-2: Annual nuclear power plant construction starts and connections to the grid, 1955–1994 (IAEA, 1995b). Open bars indicate construction starts; filled bars indicate grid connections.

General acceptance: During the last decades, there has been a decrease in acceptance of nuclear power, especially of building new nuclear power plants. A review of opinion surveys concludes that public concerns about nuclear energy focus on the following issues: doubt about economic necessity, fear of large-scale catastrophes, storage of nuclear waste, and the misuse of fissile material (Renn, 1993; The Netherlands Ministry of Economic Affairs, 1993; Slovic, 1992). Nuclear power expansion has stopped in most countries, but plans for nuclear capacity expansion remain significant in a limited number of countries, such as China, France, Japan, and Korea.

Resource base: The availability of uranium and thorium is unlikely to place a major constraint on the future development of nuclear power (Pool, 1994). Reliance on uranium alone without fast-breeder development could introduce constraints in the longer term if demand for nuclear power were to increase substantially.

Present reactor technology: Several types of reactors have been commercially developed. About 80% of the nuclear units in operation and under construction are light-water reactors (LWR); about 5% are heavy-water reactors (HWR). Gas-cooled reactors (GCR) contribute about 9% of installed capacity, but none are under construction. Liquid metal-cooled reactors (LMR) were conceived and implemented at the start of nuclear power development to use uranium more efficiently, but their deployment has not gained momentum.

Costs: Investment costs for construction of nuclear units are a major component of the total cost of nuclear-generated electricity. They are sensitive to technical parameters; regulation aspects, such as licensing lead times; and, like other capital-intensive options, the interest rate. Nuclear fuel-cycle costs include mining, spent fuel management, and disposal of low-, intermediate-, and high-level radioactive wastes (NEA, 1994). Although final repositories for high-level waste have not yet been implemented, the cost of disposal has been estimated to represent less than 20% of the undiscounted total nuclear fuel cycle cost (4.6% with 5% discount rate, 1% with 10% discount rate) (NEA, 1994). The operation and maintenance of nuclear power plants require industrial, organizational, and regulatory infrastructures, as well as highly qualified manpower—leading to generally higher operating and maintenance costs for nuclear than for fossil fuel-fired power plants.

Direct nuclear generating costs in a number of countries vary from 2.5¢ to 6¢ per kWh_e (IAEA, 1993). The direct cost of electricity from new plants, including waste disposal and decommissioning, is 2.9–5.4¢/kWh_e using a 5% discount rate and 4.0–7.7¢/kWh_e using a 10% discount rate (IEA *et al.*, 1993). Direct costs for new reactors in the Netherlands are an estimated 5.3–6.0¢/kWh_e for a 5% discount rate and 7.0–7.7¢/kWh_e for a 10% discount rate (Beeldman *et al.*, 1993). Direct electricity production costs from a new nuclear power plant are estimated to be lower than or about as high as (IEA *et al.*, 1993) or higher than (Moore and Smith, 1990; Beeldman *et al.*, 1993) those estimated for a natural gas or coal-fired power plant. Uncertainties relating to governmental decisions on such matters as licensing and regulations may affect costs in some countries. Projected levelized costs of baseload electricity generation for plants connected to the grid by the turn of the century indicate that nuclear power will remain an option in several countries where nuclear power plants are in operation or under construction (IEA *et al.*, 1993).

Environmental impact: In routine operation, nuclear power plants and their associated fuel-cycle facilities release small quantities of radioactive materials to the environment. These releases and direct exposure to radiation of workers and the public are monitored and controlled by national authorities, based upon the recommendations of the International Commission for Radiological Protection. The yearly collective dose to the world population from routine nuclear power electricity generation is less than an estimated 1% of the dose due to natural radiation sources (UNSCEAR, 1994).

The safety of nuclear facilities is assessed and regulated by independent authorities reporting to governments, taking into account international codes of practice (INSAG, 1988). The responsibilities and enforcement capabilities of these authorities vary. Before plants are licensed and throughout their operating lives, they are assessed by several techniques, including probabilistic safety assessment (INSAG, 1992). These methods are useful for identifying needs and opportunities for design improvements (U.S. NRC, 1991; INSAG, 1992). There are recognized limitations in applying this method to very-low-probability accident sequences (APS, 1975; Sørensen, 1979b). Safety is considered in design through the principle of defense-in-depth, employing successive barriers to accidental releases of radioactivity. For operational safety, a general appreciation of safety requirements through manpower training and fostering of a safety culture is central (INSAG, 1991). Deficiencies in these matters are believed to be at the root of the Chernobyl accident (INSAG, 1986). The reactor-core meltdown accident at Three Mile Island in the United States demonstrated the benefit of the defense-in-depth approach: Insignificant amounts of radioactivity were released from the plant.

Radioactive waste: All phases of the nuclear fuel cycle, other than the final disposal of spent fuel and high-level radioactive waste, are operating on an industrial scale.

High-level wastes, which contain more than 99% of the radioactivity from nuclear plants, represent after conditioning a few tens of m^3/GW(e)year. If spent fuel is reprocessed, the volume of waste would be one-tenth as large. These high-level wastes are now stored either near the reactors or at reprocessing plants. Geological repositories for high-level waste have been studied in salt and granite, for example (Carlson, 1988). Several countries are studying alternative final repositories of high-level waste, with a view toward implementation early in the next century.

Proliferation: The potential use of nuclear materials and technology for weapons has long been recognized. At the end of 1994, 178 states were parties to the 1970 Treaty on the Non-Proliferation of nuclear weapons (NPT). The treaty places conditions on the transfer of nuclear technology and materials to prevent the development of nuclear weapons. Verification is carried out by independent inspectors from the International Atomic Energy Agency (IAEA), which was established in 1957 (IAEA, 1993). An indication of the impact of the international safeguards regime is the limited number of nuclear weapon states existing at present as compared to fears expressed in the 1960s (Thorne, 1992). However, illicit trafficking of nuclear materials became a concern to governments in 1993–1994 (IAEA, 1994). A 1-GW_e nuclear power plant of the current LWR generation produces about 200 kg of plutonium (Pu) per year; future breeder reactors will produce about 1,500 kg of plutonium per year. Concerns regarding the proliferation risk arise from the accessibility to plutonium because an explosive similar to the Nagasaki bomb could be produced with only about 10 kg of plutonium (Carson Mark, 1993), or with 4 kg of plutonium or less in advanced designs (U.S. DOE, 1994a). Plutonium may be mixed with uranium as a fuel for nuclear power plants and may also be used for nuclear explosives, although the use of power reactor-grade plutonium complicates bomb design. Countries that have produced plutonium-based nuclear explosives have produced weapons-grade plutonium in reactors designed for this purpose (National Academy of Science, 1994). However, the difference in proliferation risk posed by separated weapons-grade plutonium and separated reactor-grade plutonium is small in comparison to the difference between separated plutonium of any grade and unseparated material in spent fuel (National Academy of Sciences, 1994).

New technology: Evolutionary reactor designs are being used in reactors now under construction to provide increased safety, reduced radiation doses to operators, and improved economic performance through reduced construction lead times and reduced operation and maintenance costs (Juhn and Kupitz, 1994). Cost reductions can be obtained by streamlining the reactor's systems and reducing the amount of material and manufactured components required for construction. Reactors with such improved designs are under construction in Canada, France, and Japan.

Designs incorporating more innovative features are being developed in some countries, on the grounds that evolutionary improvements will not suffice to provide the safety that the public and the investors want. In particular, systems with inherently safe characteristics and more passive safety features are being developed to reduce the probabilistic risk of accidents, as well as on-site and off-site impacts in the event of a severe accident. In particular, the concept of Modular High-Temperature Gas-Cooled Reactors—in which graphite is used as the moderator and helium as the coolant—has attractive safety features. A 30-MW_{th} test reactor is under construction in Japan.

Advanced reactors also are being designed and developed to address the challenges of higher reliability and cost reductions while satisfying increasingly demanding safety and waste-management requirements (Kupitz, 1992; IAEA, 1995a). In a recent study for the Netherlands government, researchers have concluded that the majority of these concepts for new power plants are likely to meet current safety criteria (The Netherlands Ministry of Economic Affairs, 1993). The level of safety improvements, however, is unclear (Mårtensson, 1992).

Concerns about the future production of Pu in a world with a large nuclear capacity have stimulated proposals for criteria for diversion-resistant nuclear power (Williams and Feiveson, 1990). Preliminary proposals have been made for significant reductions in plutonium production through the use of fuels such as denaturated thorium—for example, high-energy accelerator devices (Carminati *et al*., 1993). Interest in LMRs has been revived in view of their potential use in the management and disposal of civil radioactive waste, as well as fissile materials arising from dismantling of nuclear weapons (National Academy of Science, 1994; Chang, 1993). The use of LMRs for transmutation of actinides contained in irradiated fuels from LWRs also has been investigated (NEA, 1995a). Other strategies are being investigated for reducing the period during which radioactive waste repositories need to be controlled. For example, partitioning actinides and transmuting them by neutrons or high-energy protons can substantially reduce the volume of long-lived isotopes (The Netherlands Ministry of Economic Affairs, 1993).

Other concepts are being developed with the objective of enhancing the use of nuclear power for nonelectrical applications. Some nuclear plants supply process and district heat. In the longer term, nuclear energy could be deployed for hydrogen production (Marchetti, 1989) (see Section 19.2.6.4). Market studies for small- and medium-size reactors (SMRs) have shown that nuclear power could in principle be more broadly deployed for district heating, heat supply to industrial complexes (IEA, 1993c), and production of potable water (IAEA, 1992a, 1992b).

In the longer term, it might also be possible to generate electricity from nuclear fusion instead of fission (IFRC, 1990). The primary fuels for fusion reactors—deuterium and lithium—are so abundant that fusion would be a practically inexhaustible source of energy. The conditions required for self-sustaining net power-producing fusion reactions on the Earth have not yet been attained, however. The development and implementation of fusion reactors requires demonstration of scientific, technological, and commercial feasibility. It is not expected that fusion plants could be available on a commercial scale before the second half of the next century (Colombo and Farinelli, 1992).

A major drive will be needed to achieve the early rehabilitation of nuclear energy if it is to contribute to fossil fuel use reductions in the next century. The continuing concern of many members of the general public and many policymakers with regards to safety and proliferation issues, however, may remain a severe constraint on nuclear power generation in many countries (WEC, 1993).

19.2.5. Switching to Renewable Sources of Energy

Renewable sources of energy, including biomass and hydropower, contributed about 20% of the world's primary energy consumption in 1990 (see Table B-2 in Chapter B).

The resource base for renewable energy technologies is very large in comparison to projected world energy needs (see Table B-4 in Chapter B). Impressive technical gains in renewable energy utilization have been made during the past decade (U.S. DOE, 1990; Johansson *et al*., 1993b; Ahmed, 1994; Kassler, 1994; WEC, 1994).

Renewable sources of energy used sustainably have small emissions of GHGs. The establishment of an infrastructure for large-scale use of renewable sources of energy will generate indirect emissions of GHGs if this infrastructure is put in place using fossil fuels. On the other hand, renewable energy sources could be considered for this, thereby giving rise to very little of such indirect emissions. There are also some GHG emissions associated with the unsustainable use of biomass—for example, from reducing the amount of standing biomass and from decomposition of biomass associated with the establishment of some dams. By and large, the increased use of renewable sources of energy offers substantial reductions of GHG emissions compared to the use of fossil fuels.

19.2.5.1. Hydropower

Hydroelectricity, which depends ultimately on the natural evaporation of water by solar energy, is the only renewable resource used on a large scale for electricity. In 1990, 2,200 TWh were generated, accounting for 18% of the world's total electricity generation, with small or no emissions of GHG.

The energy potential of hydropower is determined by the annual volume of runoff water (47,000 km^3) and by the height it falls before reaching the ocean. Estimates of the theoretical annual potential of world hydroelectricity range from 36,000 to 44,000 TWh, corresponding to 340 to 410 EJ_{th} with conventions from Table B-2 in Chapter B (Raabe, 1985; Boiteaux, 1989; Bloss *et al*., 1980). This gross theoretical potential is much larger than the technically usable potential, which in turn is substantially larger than the economically exploitable potential. The technically usable potential is an estimated 14,000 TWh/yr (WEC, 1992). The economically exploitable potential—after social, environmental, geological, and other economic constraints are considered—is smaller. The world's long-term economic hydroelectric potential may be on the order of 6,000–9,000 TWh/yr (Moreira and Poole, 1993).

Hydroelectric plants vary in size and share of the world's hydropower potential. Small-scale hydropower, often defined as installations smaller than 10 MW, contributes about 4% of world hydroelectricity (WEC, 1992, 1994). Small plants have a large potential to contribute to socioeconomic development in rural areas. Their potential overall contribution to GHG emissions is limited, however.

Hydropower costs are most commonly measured in terms of the cost per kilowatt installed. With some exceptions, there is surprisingly little systematic data available on the cost of individual plants (Electrobras, 1987; Lazenby and Jones, 1987; Moore and Smith, 1990). Total investment costs for 70 developing countries for the 1990s (Moore and Smith, 1990) suggest that the cost of new hydroelectricity is 7.8¢/kWh.[2]

[2] This is the average value for hydropower plants under construction for this decade. The investment is from Moore and Smith (1990); electricity cost is obtained through average utilization factor (0.42), interest rate (10%), and operational cost (1 ¢/kWh).

An estimate of the value of hydropower must account for its capability to vary the power level over wide ranges, providing a means of handling variations in electricity demand and intermittent power generation from wind and solar sources (Kelly and Weinberg, 1993).

Hydropower is not free of GHG emissions. Bacterial decomposition of biomass in flooded reservoirs produces CH_4 and CO_2. The impact on global warming, in comparison to fossil fuel power generation, depends on the amount and timing of the gases formed. Dams that flood large areas with large quantities of biomass (including underground biomass) generate GHG emissions (Rudd *et al.*, 1993; Pinguelli Rosa and Schaeffer, 1994). The magnitude of this effect can be determined only on a case-by-case basis.

Most hydroplants require a reservoir, which can significantly affect people (through relocation), the terrestrial ecosystem, and the river itself. The social effects of relocation of people are not well known (Cernea, 1988). The area inundated by dams generally has higher agricultural value and a higher population density than the surrounding region as a whole.

The construction phase of a hydroelectric plant has social consequences and direct environmental impacts, such as water diversion, drilling, slope alteration, reservoir preparation, and the creation of an infrastructure for the large workforce (Moreira and Poole, 1993). The social consequences of a large workforce include migration, shanty towns with increased public-health problems, pockets of urban and rural poverty, destruction of the character of local communities, and intense deforestation (Moreira and Poole, 1990). On the positive side, the local transportation network and related industries often grow. The additional infrastructure stimulates regional economic development and has been widely viewed as a regional development tool (Moreira and Poole, 1993). Well-designed installations using modern technology that cascade the water through a number of smaller dams and power plants may reduce the environmental impact of the system (Henry, 1991).

Water quality is a major problem for hydroelectric planners. The inundation of land reduces the production potential for biomass for energy in addition to generating GHGs through biological decomposition (Garzon, 1984). Water management must allow for irrigation (Veltrop, 1991). Sedimentation is a problem in reservoirs and river deltas (Deudney, 1981).

Dams have a significant impact. Dam failure has caused significant losses of life and property (Smets, 1987; Laginha Serafim, 1984). Dams may prevent fish migration and stop water flow, which is a necessity for some fish (Petrere, 1990).

Disturbing aquatic ecosystems in tropical areas can induce indirect environmental effects; for example, increased pathogens and their intermediate hosts may lead to an increase in fatal human diseases such as malaria, schistosomiasis, filariasis, and yellow fever (Waddy, 1973).

The social and environmental constraints on hydropower development must be carefully evaluated in each situation. The evaluation should include the value of avoiding other forms of electricity generation that may bring unwanted social and environmental effects.

19.2.5.2. Biomass

Biomass energy is consumed at an annual rate of 47 EJ (WEC, 1994) to 55 EJ (Hall *et al.*, 1993), mainly for cooking and heating in developing countries. It is used for some small-scale industry, though there is some experience at larger scales.

There is no net atmospheric CO_2 build-up from using biomass grown sustainably because CO_2 released in combustion is compensated for by that withdrawn from the atmosphere during growth. Modern biomass energy also offers the potential for generating income in rural areas (Johansson *et al.*, 1993a). This income could allow developing-country farmers to modernize their farming techniques and reduce the need to expand output by bringing more marginal lands into production (Riedacker and Dessus, 1991). In industrialized countries, biomass production on excess agricultural lands could allow governments eventually to phase out agricultural subsidies (Williams, 1994a).

19.2.5.2.1. Biomass production

Potential biomass energy supplies include municipal solid waste (MSW), industrial and agricultural residues, existing forests, and energy plantations.

MSW: MSW is produced at per capita rates of 0.9–1.9 kg/day in industrialized countries. Energy contents range from 4–13 MJ/kg. Energy can be produced by incineration, biodigestion, or thermochemical gasification to produce electricity, process heat, or fluid fuels. An attraction is the low price to potential users, who may be paid to take the waste because of the high cost of disposal in landfills. If MSW is burned, attention must be given to controlling air pollutants, some of which are carcinogenic compounds (WEC, 1994). Air pollution may be virtually eliminated with some advanced energy-conversion technologies (Chen, 1995).

Industrial and agricultural residues: The energy content of organic waste byproducts of the food, fiber, and forest-product industries is more than one-third of total global commercial energy use (Hall *et al.*, 1993). Some residues should be left at the site, however, to ensure the sustainable production of the main product. If removed and converted to biogas, the nutrients recovered in the digester should be returned to the site. Some recoverable residues would be better used for other purposes, and it will not be practical or cost-effective to recover all residues. Recoverable crop, forest, and dung residues have been estimated to be about 10% of present global commercial energy use (Hall *et al.*, 1993).

Existing forests: The difference between annual increment and harvest for the world's forests has an energy content equal to one-third of world primary energy use (Hall *et al*., 1993). Large increases in wood recovery for energy, however, would require more intensive forest management and raise concerns about potential loss of biodiversity and natural habitat. Thus, the contribution of existing forests to energy supplies depends on local conditions.

Plantation biomass: Dedicated plantations of woody or herbaceous (annual or perennial) crops offer a large potential for biomass energy. At present there are about 100 million hectares of industrial tree plantations worldwide, of which about 6 million hectares are fast-growing hardwoods, the trees most suitable for energy applications (Hall *et al*., 1993).

Excess agricultural lands are good candidates for plantations in industrialized countries. The potential for using such lands for biomass energy in Europe has been estimated at 33 Mha by 2020 (Hall, 1994) and 40 Mha for the European Union in the long term (Wright, 1991). Also, it has been estimated that 50–100 Mha of agricultural lands in Europe might become available for other purposes (WRR, 1992). In the United States, idle cropland totaled 33 Mha in 1990 and is projected to grow to 52 Mha by 2030, despite an expected doubling of exports of maize, wheat, and soybeans (SCS, 1989)—largely because of expected increased crop yields.

Concerns about future food supplies (Ehrlich *et al*., 1993; Kendall and Pimentel, 1994; Brown, 1993) have led some to suggest that land will not be available for biomass production for energy in Africa and other developing regions (Alcamo *et al*., 1994). The outlook for food production may not be so bleak, however, if agriculture can be modernized in the developing world. With a continuation of historical trends in grain yields, considerable unforested land would be available for biomass energy production in many developing regions despite increased food requirements for a growing population (Larson *et al*., 1995). Such outcomes depend on the availability of income to modernize agriculture, as well as whether intensified agricultural production can be made environmentally acceptable (see Section 19.3.1.4 and Chapter 25).

Deforested and otherwise degraded lands might be targeted for energy plantations. For tropical regions, Grainger (1988, 1990) has estimated that there are nearly 2,100 Mha of degraded land, of which 30% is theoretically suitable for reforestation. The challenge of restoration is to find a sequence of plantings that can lower ground temperature and restore the organic and nutrient content as well as the moisture level of the soils to attain

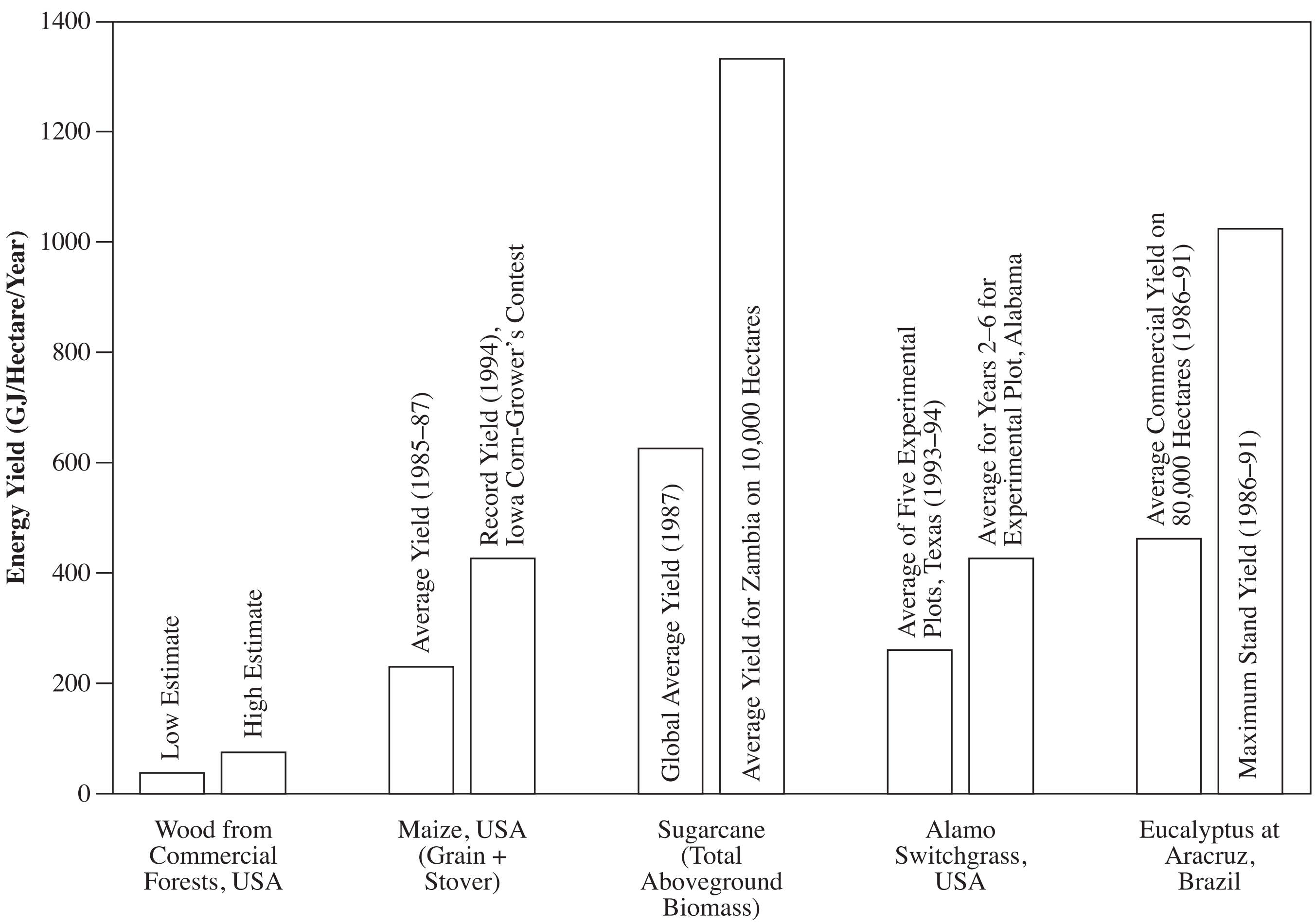


Figure 19-3: Actual biomass yields from various activities.

high and sustainable crop yields (OTA, 1992). Intensive R&D is needed to identify the most promising sites and restoration strategies (Riedacker, 1993; Johansson *et al*., 1993a).

The objective is for plantations to achieve high sustainable yields at low costs with minimal environmental impact. The characteristics of an ideal energy crop have been described by Goudriaan *et al*. (1991). Biomass energy must be considered in integrated land-use planning (see Chapter 25), with attention given to the economic well-being of the local community and to environmental concerns such as chemical pollution of ground water, soil erosion, and loss of biodiversity and landscape diversity (Beyea *et al*., 1991; Shell/WWF, 1993; OTA, 1993; Gustafsson, 1994; NBR, 1994; WEC, 1994). Biomass used for energy via thermochemical processes offers much more flexibility than biomass used for food in the choice and mix of species and cultivation practices for addressing environmental concerns because the only biomass attribute of importance then is production cost (Williams, 1994a).

Little biomass has been grown on plantations for energy. Thus, estimates of prospective yields are based on experience with crops grown for food and fiber, limited commercial experience and considerable experimental work with candidate bioenergy crops, and expected improved yields from new technology. The highest biomass yields that have been achieved over large areas are for sugar cane (see Figure 19-3): The 1987 worldwide average, aboveground biomass yield was 36 dry tons per hectare per year (dt/ha/yr); the yield for Zambia (averaged over 10,000 ha) was 77 dt/ha/yr (Hall *et al*., 1993). At Aracruz in Brazil from 1986 to 1991, yields (stemwood diameter >7 cm) of eucalyptus grown for pulp averaged about 23 dt/ha/yr; the maximum stand yields achieved in the same period were 52 dt/ha/yr (see Figure 19-3). About 11,000 ha of willow plantations have been established for energy in southern Scandinavia. There the yield on the best 100 hectares has averaged 10–12 dt/ha/yr (Ledin *et al*., 1994) and is projected to be 14–17 dt/ha/yr in 20 years (Christofferson, 1995). In the United States, researchers project that by 2020 yields for hybrid poplar and switchgrass will average 15–20 dt/ha/yr in regions where conditions are favorable for such crops (Walsh and Graham, 1995).

Plantation biomass costs already are favorable in some developing countries. On the basis of commercial experience with eucalyptus in northeast Brazil, an estimated 13 EJ/yr of biomass could be produced on 50 Mha at an average cost for delivered wood chips of $1.7/GJ (Carpentieri *et al*., 1993). Costs are much higher in industrialized countries. A major U.S. Department of Energy/Department of Agriculture study estimates, however, that a strong and sustained R&D effort could lead by 2020 to 5 EJ/yr of plantation biomass in the United States at a delivered cost of $1.5/GJ or less (Graham *et al*., 1995). A related study carried out by the U.S. Environmental Protection Agency estimates that land-use competition could increase land rental rates. Thus, the biomass price in 2020 for 5 EJ/yr would be $1.8/GJ under essentially the same technical assumptions about yields and costs (Turnure *et al*., 1995). For comparison, the U.S. Department of Energy projects that the average price of coal to U.S. utilities will be $1.3/GJ in 2010 (EIA, 1995) under projected demand conditions. Displacement of coal by biomass on a large scale would tend to drive future coal prices to levels that are lower than without this competition.

The energy output–input ratio for plantation biomass depends on crop species, yield, and production technology. Although this ratio can be low for high-quality food crops such as grain, it is generally high for energy crops with good economic prospects. Some estimates are 15:1 for willow (Johansson, 1993); 29:1 for trees grown in short-rotation coppices (Foster and Matthews, 1994); and, in the United States, 11:1 for switchgrass, 12:1 for sorghum, and 16:1 for hybrid poplar (Turhollow and Perlack, 1991).

19.2.5.2.2. Electric power generation

Electricity generation from biomass can take place at scales ranging from a few kilowatts for rural village or agricultural applications, to tens of megawatts for present industrial applications, to hundreds of megawatts for advanced industrial applications.

Producer gas engines: The electrical loads of many poor rural villages of the developing world are in the range of 10–200 kW_e. Producer gas-engine generator sets based on the use of biomass gasifiers coupled to small reciprocating engines are well-matched to these loads (Ravindranath, 1993; Ravindranath and Hall, 1995). These generators often use diesel fuel, but biomass-derived producer gas could replace 75–95% of this diesel fuel.

Modest resources have been committed to developing this technology, mostly since the early 1970s. Until recently, most biomass-producer gas-engine projects failed, largely because of excessive tar formation in the gasifier and maintenance problems posed by tars. These problems have been solved, however; successful field demonstrations have been carried out, and the technology is ready for large-scale commercial applications (Mukunda *et al*., 1993, 1994). For 100-kW_e units operated on biomass costing $2/GJ, electricity can be produced for 10–15¢/kWh; for low-cost biomass (for example $0.85/GJ for a village plantation in south India), electricity can be produced for less than 10¢/kWh (Larson, 1993), making this technology an attractive option for applications remote from electric grids where biomass is available.

Conventional steam-turbine technology: In many countries, biomass residues are used to generate electricity or CHP with conventional steam turbine technologies. The United States has an installed biomass steam-electric generating capacity of more than 8,000 MW_e (Turnbull, 1993a). Although they tend to be much smaller (typically

20 MW_e) than fossil fuel steam-electric plants, relatively capital-intensive, and energy inefficient (Turnbull, 1993b), commercial biomass steam-electric plants can provide cost-competitive power where biomass prices are low, especially in CHP applications.

Improving steam-turbine cycles: In the near term, steam-electric plant performance can be improved by cofiring large boilers with biomass. This can be achieved by converting existing grate-fired boilers to fluidized bed boilers at modest cost—$40–100/kW$_e$, including fuel handling (Saviharju, 1995). Biomass cofiring systems are used extensively in Nordic countries.

Because costly sulfur cleanup is not needed for biomass, optimizing steam-turbine cycle technology can lead to specific capital costs and efficiencies for 100 MW_e plants that are comparable to those for 500 MW_e coal plants requiring sulfur cleanup (RTI *et al*., 1993). Less capital-intensive, more energy-efficient technologies are needed to make the more abundant and costly biomass sources competitive.

Advanced power cycles involving gasification: Higher efficiency and lower unit capital costs can be realized with advanced conversion technologies. Biomass-integrated gasifier/gas turbine (BIG/GT) cycles are the focus of present development efforts (Williams and Larson, 1993).

Because biomass generally contains little sulfur, gases exiting the gasifier can be cleaned at higher temperatures than is feasible for coal (hot-gas sulfur-removal technology is not commercially proven). Thus, biomass is well-matched to air-blown gasifiers, which tend to be less costly than the oxygen-blown gasifiers used in commercial coal integrated gasifier/gas turbine systems at the scales of interest for biomass power systems. Efficiencies of 40–45% are expected to be achievable (Elliott and Booth, 1993; Consonni and Larson, 1994).

Various projects to demonstrate BIG/GT technology are underway. A 6-MW_e pilot plant is being tested at Värnamo, Sweden. A 30-MW_e commercial demonstration plant is being planned for the northeast of Brazil (with initial operation scheduled for 1997–1998), with support from the Global Environment Facility (Elliott and Booth, 1993). During 1993–1994, two Finnish gasification CHP power demonstration projects (larger than 50 MW_e) were announced, as were three relatively small-scale (7–12 MW_e) demonstration projects (a CHP plant for Denmark and two power-only plants for the UK and Italy) with support from the European Union. Other demonstration projects are being planned in Belgium, the Netherlands, and the United States.

BIG/GT power plants would have low sulfur dioxide (SO_2) particulate, and thermal NO_x emissions, but NO_x emissions could arise from fuel-bound nitrogen (N). NO_x emissions could be kept low by growing biomass with low N content and/or selectively harvesting portions of the biomass having high C/N ratios. For example, trees could be harvested in winter, after the leaves—in which the N is concentrated—have fallen (Ledin and Alriksson, 1992). Stack-gas emission controls might still be needed in areas where there are severe restrictions on NO_x. Gasifier and/or combustor modifications under development offer the promise of suppressing NO_x formation (Leppalahti, 1993). Successful development would obviate the need for stack-gas controls.

The ability of biomass to compete with coal depends on relative fuel prices and relative performances and costs for conversion technologies. A U.S. Environmental Protection Agency assessment exploring prospective advances for both biomass and coal (Turnure *et al*., 1995) considers future biomass power plants with characteristics that range from a 0.5% lower heat rate and a unit capital cost that is approximately 2% less than for coal plants, to biomass plants characterized by an 8% higher heat rate and a unit capital cost that is 20% higher than for coal plants. Under the first set of conditions, differences in fuel cost alone would drive the economic comparison between biomass and coal; for the second, subsidies in excess of 1¢/kWh would be required to put biomass on a competitive footing with coal, even under relatively optimistic assumptions about biomass production costs.

Other studies suggest that if R&D goals are fully realized for biomass production (Graham *et al*., 1995) and for the commercialization of advanced BIG/GT technologies designed to exploit the intrinsic characteristics of biomass feedstocks (Williams, 1995a), biomass has good prospects for competing with coal by 2020 in many circumstances, even if the price of biomass is somewhat higher than the price of coal. In the long run, key distinguishing features of biomass and coal IG/GT technologies are likely to arise from the sulfur and moisture contents of the feedstocks.[3] A framework for a quantitative economic comparison highlighting these distinguishing features is offered by fixed-bed integrated gasifier/intercooled steam-injected gas

[3] Even though existing biomass steam-electric plants (fired with forest product and agricultural industry residues or MSW) are characterized by modest scales (25 MW_e a typical plant size), scale is not likely to be a key distinguishing characteristic between biomass and coal plants when advanced BIG/GT technologies using plantation biomass become established in the market, because electric generation costs are not very sensitive to transport distances for the fuel (Faaij *et al*., 1995; van den Broek *et al*., 1995). Site-specific analyses of such applications of pressurized BIG/GT systems in the U.S. and Brazil—taking into account the areal distribution of biomass supplies and power plant scale economies—have shown that electricity costs are minimized for capacities in the range 230–320 MW_e (Marrison and Larson, 1995a, 1995b). Moreover, if air-blown gasifiers with hot-gas sulfur cleanup are successfully developed (Corman, 1986), it will be possible to have low-cost coal IG/GT plants at scales much smaller than those optimal for current IG/GT technology based on oxygen-blown gasifiers, for which costs are very scale-sensitive. Even if oxygen-blown gasifiers remain the norm for coal, future coal IG/GT plants may be smaller than the optimal for current technology—because of ongoing progress in reducing costs for air separation generally and in particular for air separation at modest scales, as a result of advances relating to pressure swing adsorption and membrane gas separation systems (Simbeck, 1995).

turbine (IG/ISTIG) systems[4] at the same scale (~110 MW_e) for both coal and biomass (Williams and Larson, 1993). The coal variant of IG/ISTIG, which involves hot-gas sulfur cleanup, has been proposed as a low-cost option for coal (Corman, 1986). The biomass variant does not require sulfur cleanup but does require a biomass dryer. A promising dryer option involves drying biomass in pressurized superheated steam and using the water evaporated from biomass as steam in the BIG/ISTIG system via process integration. For IVOSDIG (involving steam drying of biomass coupled to a steam-injected gas turbine), the first generation of which is being developed in Finland, it has been shown that the plant efficiency (HHV basis) is nearly independent of the fuel moisture content (Hulkkonen *et al*., 1991). The capital cost penalty for such a steam dryer for BIG/ISTIG is estimated to be $100/kW, about 40% of the estimated incremental cost for hot gas sulfur cleanup for the coal IG/ISTIG. Largely because of the resulting net capital cost advantage to biomass, IG/ISTIG electricity from biomass costing $2/GJ could potentially compete with IG/ISTIG electricity from coal for coal prices in the range $1.4–1.7/GJ (depending on the market value of the sulfuric acid recovered as a byproduct) (Williams, 1995a).

Biomass-integrated gasifier/fuel cell (BIG/FC) systems involving molten carbonate or solid-oxide fuel cells prospectively would be even more energy-efficient than BIG/GT systems and would be especially well-suited for industrial cogeneration applications requiring high-temperature process heat. Although little attention has been given to such systems in development efforts, biomass would, in several respects, be a more attractive feedstock than coal for gasification-based fuel cell applications (Kartha *et al*., 1994). If successfully developed, BIG/FC systems could extend the range of economically attractive power generation options to smaller scales (~1 MW_e) than would be feasible with BIG/GT systems.

19.2.5.2.3. Biogas production

Simple anaerobic digesters are used in rural areas of some developing countries to produce biogas from manure and crop residues at scales ranging from household to village. They provide fuel for cooking and power (Rajabapaiah *et al*., 1993), byproducts in the form of fertilizer and feed for pigs and fish farms, and substantial environmental and human health benefits (DEPE, 1992). The future potential is large, particularly if organizational issues are satisfactorily resolved—for example, if local expertise is ensured in operation and maintenance and if users take responsibility for collecting biomass for the biogas plant (Rajabapaiah *et al*., 1993).

In industrialized countries, the focus is on industrial plants with capacities of several million cubic meters of biogas/yr, compared with 250–300 m^3/yr for household plants in China (Wang *et al*., 1992) and 10,000 m^3/yr for village-scale plants in India (Rajabapaiah *et al*., 1993).

In the most common application in industrialized countries, manure and other organic wastes are pretreated and passed through plants for pasteurization, digestion, separation, and gas purification to produce biogas, along with byproducts that include fertilizer and compost. The gas produced in large installations in Denmark is used in gas engines for CHP or in boilers for DH. Experiments with other uses are in progress, including compressed gas for vehicles (Stewart and McLeod, 1980; Danish Energy Agency, 1992).

Economics: Direct costs have declined with experience for Danish plants. Although the government has provided a 25–50% subsidy, the best plant, selling gas at $10 per GJ, would roughly break even in Denmark even if there had been no subsidy (Danish Energy Agency, 1992).

In India, after experiences well short of expectations (Comptroller and Auditor General of India, 1994), cattle-dung biogas plants have now been demonstrated at village scale to be economically viable for providing biogas-generated electricity (~5 kW_e) for lighting and pumping water. Plans are underway to replicate the technology in many villages (Reddy *et al*., 1994).

Energy balance: For the 10 large Danish biogas plants, the net external energy requirement—considering fuel for transporting manure to the plant and the fertilizer value of the returned residue—is just 0.7% of net production, corresponding to an energy payback of three days (Tafdrup, 1993).

GHG emissions: The average GHG emissions avoided by using the biogas produced by the 10 Danish plants instead of coal for CHP is 17 kgC/m^3 of biomass converted. Moreover, biogas production from manure reduces emissions from spreading manure directly on fields equivalent to about 15 kgC/m^3 of biomass converted, so that total GHG emissions are reduced by 32 kgC/m^3 of biomass converted (Tafdrup, 1993).

19.2.5.2.4. Biofuels for transport

Interest in alternative transport fuels has been driven largely by concerns about oil supply security and urban air quality. These concerns have led Brazil and the United States to adopt policies promoting alternative vehicles and fuels. In light of increasing air pollution in the world's megacities (UNEP/WHO, 1992), such policies are likely to become more widespread.

Traditional biofuels for transport: Efforts to produce biofuels for transport have focused on ethanol from maize, wheat, and sugar cane and on vegetable oils such as rapeseed oil. The most substantial commercial programs are in Brazil and the United States. In 1989, Brazil produced 12 billion liters of fuel ethanol from sugar cane, which was used to power 4.2 million

[4] While IG/ISTIG technology is not currently being developed, its successful development could lead to substantial electricity cost reductions relative to first generation IG/GT technologies for both coal and biomass. Comparing coal and biomass in the context of IG/ISTIG technology represents the competing feedstocks fairly and facilitates a comparison of their key distinguishing characteristics.

cars running on hydrated ethanol and 5 million cars on gasohol, a gasoline-ethanol blend (Goldemberg *et al*., 1993). In 1993, the United States produced 4 billion liters of ethanol from maize for gasohol applications.

All traditional biomass-derived transport fuels are uneconomic at present. Substantial cost reductions are being made for sugar cane-derived ethanol, however (Goldemberg *et al*., 1993). Moreover, there are good prospects for making cane-derived ethanol competitive at the present low world oil price if electricity is cogenerated from cane residues using BIG/GT technology along with ethanol from cane juice (Williams and Larson, 1993). In contrast, the prospects are poor for making ethanol economically from grain (Wyman *et al*., 1993).

Most traditional biofuels are inefficient users of land, with low yields of transport services (vehicle km/ha/yr) compared with what is achievable with advanced technologies using woody biomass feedstocks (Table 19-4). Many also have marginal energy balances. Fossil energy inputs to produce ethanol from wheat, maize, or sugar beets are likely to be comparable to the energy content of the ethanol; for rape methyl ester derived from rapeseed, fossil energy inputs are likely to be about half the energy in the rape methyl ester (Lysen *et al*., 1992; IEA, 1994b). Greenhouse performance also tends to be marginal. For maize, estimates of net fuel-cycle emissions of CO_2 have ranged from somewhat more (Ho, 1989) to somewhat less (Marland and Turhollow, 1990) than for gasoline. Total life-cycle GHG emissions may even be somewhat higher than for reformulated gasoline, which contains more oxygen to improve combustion and thereby reduce emissions (DeLuchi, 1991). For rape methyl ester, life-cycle CO_2 emissions are less than for fossil fuels (Lysen *et al*., 1992). There also may be significant emissions of nitrous oxide (N_2O), a powerful GHG, as a result of the conversion of some nitrogen in fertilizer to N_2O. These emissions depend on the type of fertilizer and application (Lysen *et al*., 1992; Muschalek and Sharmer, 1994), however, and there are large uncertainties (Gosse, 1994; Bernhardt, 1994).

It is now generally believed that alcohol fuels—especially when blended with gasoline and used in flexible-fuel internal-combustion engine vehicles (ICEVs)—offer little or no

Table 19-4: *Energy yield for alternative feedstock/conversion technologies.*

Option	Feedstock Yield (dry tons/ha/yr)	Transport Fuel Yield (GJ/ha/yr)	Transport Services Yield[8] (10^3 v-km/ha/yr)
Rape Methyl Ester (Netherlands)[1]	3.7 of Rapeseed	47	21 (ICEV)
EthOH from Maize (USA)[2]	7.2 of Maize	76	27 (ICEV)
EthOH from Wheat (Netherlands)[3]	6.6 of Wheat	72	26 (ICEV)
EthOH from Sugar Beets (Netherlands)[4]	15.1 of Sugar Beets	132	48 (ICEV)
EthOH from Sugar Cane (Brazil)[5]	38.5 of Cane Stems	111	40 (ICEV)
EthOH, Enzymatic Hydrolysis of Wood (present technology)[6]	15 of Wood	122	44 (ICEV)
EthOH, Enzymatic Hydrolysis of Wood (improved technology)[6]	15 of Wood	179	64 (ICEV)
MeOH, Thermochemical Gasification of Wood[7]	15 of Wood	177	64/133 (ICEV/FCV)
H_2, Thermochemical Gasification of Wood[7]	15 of Wood	213	84/189 (ICEV/FCV)

[1] Per ton of seed: 370 liters of rape methyl ester plus (not listed) 1.4 tons of straw (Lysen *et al*., 1992).
[2] For wet milling, assuming the U.S. average maize yield, 1989–1992; per ton of grain: 440 liters of ethanol plus (not listed) 0.35 tons of stover (out of 1 ton of total stover, assuming the rest must be left at the site for soil maintenance), 275 kg of corn gluten cattle feed, and 330 kg of CO_2 (Wyman *et al*., 1993).
[3] Per ton of seed: 455 liters of ethanol plus (not listed) 0.6 tons of straw (Lysen *et al*., 1992).
[4] Per ton of sugar beet: 364 liters of ethanol (Lysen *et al*., 1992).
[5] For the average sugar cane yield in Brazil in 1987 (63.3 tons of harvested cane stems, wet weight); per ton of wet cane stems: 73 liters of ethanol (Goldemberg *et al*., 1993). In addition, (not listed) the dry weight of the attached tops and leaves amounts to 0.092 tons and that for the detached leaves amounts to 0.188 tons per ton of wet stems—altogether some 18 dry tons/ha/yr (Alexander, 1985).
[6] Per ton of feedstock: 338 liters of ethanol plus (not listed) 183 kWh (0.658 GJ) of electricity, present technology; 497 liters of ethanol plus (not listed) 101 kWh (0.365 GJ) of electricity, improved technology (Wyman *et al*., 1993).
[7] For the indirectly heated Battelle Columbus Laboratory biomass gasifier; per ton of feedstock: 11.8 GJ of methanol or 14.2 GJ of hydrogen; per ton of feedstock, external electricity requirements are 107 kWh (0.38 GJ) for methanol or 309 kWh (1.11 GJ) for hydrogen (Williams *et al*., 1995a, 1995b).
[8] Fuel consumption rate of the vehicles (in liters of gasoline-equivalent per 100 km) assumed to be 6.30 for rapeseed oil (assumed to be the same as for diesel), 7.97 for ethanol, 7.90 for methanol, and 7.31 for hydrogen used in internal combustion engine vehicles (ICEVs), and 3.81 for methanol and 3.24 for hydrogen used in fuel-cell vehicles (FCVs) (DeLuchi, 1991). Note that 1 liter of gasoline equivalent = 0.0348 GJ, HHV.

air-quality advantages, other than reduction in carbon monoxide (CO) emissions (Calvert *et al*., 1993). Moreover, reformulated gasolines can meet or surpass the air-pollution reductions of alcohol-gasoline blends (BEST, 1991). With methanol, CO emissions would be reduced, and emissions of volatile organic compounds would be less problematic than for gasoline, but NO_x emissions would probably not be reduced. Ethanol offers lesser air-quality benefits than methanol and may produce more ozone per carbon atom (Calvert *et al*., 1993). Because of such problems with traditional biofuels, advanced technologies are receiving increased attention.

Advanced biofuels: Advanced biofuels derived from low-cost woody biomass could offer higher energy yields at lower cost and with lower environmental impacts than most traditional biofuels (IEA, 1994b). The advanced biofuel that has received the most attention is ethanol derived from wood via enzymatic hydrolysis (Wyman *et al*., 1993). For a woody feedstock yield of 15 dry t/ha/yr—which is generally believed to be achievable in large-scale production—the ethanol yield could be more than twice that from grain (Table 19-4). If the U.S. Department of Energy's year-2000 goals for performance and cost are met, energy balances would be favorable; life-cycle emissions of CO_2 for ethanol production and use in ICEVs (in gC/km) would be only about 2% of those from such vehicles operated on reformulated gasoline (Wyman *et al*., 1993). Furthermore, ethanol will be competitive with gasoline if oil prices are greater than about \$25/bbl (Wyman *et al*., 1993). For comparison, French studies indicate that ethanol from grain will not be competitive until oil prices reach \$40–45/bbl (Torck *et al*., 1988). The major shortcoming of the technology is that it may not lead to air-quality improvements beyond what can be achieved with reformulated gasoline. However, low emissions, along with a two to three-fold gain in fuel economy, might be practically achievable using either fuel with a so-called hybrid car that has an electric drive train, an electric generator driven by a small internal-combustion engine that would provide baseload power, and a small battery or other device for providing peak power (Ross, 1994; Colombo and Farinelli, 1994).

Other advanced fuels include methanol and hydrogen derived from biomass via processes that begin with thermochemical gasification. Used in fuel-cell vehicles (FCVs), they offer good prospects for dealing with the multiple challenges of transportation. Recent advances suggest that the proton-exchange-membrane (PEM) fuel cell is an attractive alternative to the internal combustion engine for cars (AGTD, 1994; Williams, 1993, 1994b), buses, trucks, and trains (see Section 19.2.6.4).

If FCVs were introduced, hydrogen or methanol fuel would be produced initially by steam-reforming natural gas. This is the least-costly route, for which the required technology is commercially available. On the basis of projected prices for natural gas, coal, and biomass, production costs would be comparable for these three feedstocks before 2025 (Williams, 1996).

The prospect that biomass could compete with coal in the longer term reflects the more favorable characteristics of biomass as a feedstock for gasification (Williams *et al*., 1995a, 1995b). Low sulfur content gives biomass a processing cost advantage compared with coal. In addition, if the biomass gasifier is designed to exploit the much higher reactivity of biomass compared to coal, unit capital costs can be reduced. For both coal and biomass, the initial step involves gasification to produce a synthesis gas (mainly CO and H_2). Coal is gasified in oxygen to produce the desired synthesis gas. The high gasification temperatures needed are achieved by direct heating—that is, by burning some of the coal in place. To take advantage of economies of scale for the oxygen plant, the coal conversion facilities would be large. Because of its much higher reactivity, biomass can be gasified at much lower temperatures—a property that makes it possible to avoid the use of costly oxygen-blown gasifiers and instead to gasify the biomass in steam using indirectly heated gasifiers in smaller facilities.

The yield for methanol or hydrogen produced from woody biomass would be comparable to that for ethanol derived via enzymatic hydrolysis (see Table 19-4). The potential for displacing gasoline used in ICEVs with biomass-derived methanol or hydrogen used in FCVs, however, would be more than twice that for ethanol used in ICEV applications because FCVs would be more than twice as energy-efficient as ICEVs. The FCV thus offers the potential for substantially increasing the role of biomass in transportation, supporting up to seven times as many vehicle-km of transport services per hectare as ethanol derived from grain used in ICEVs (see Table 19-4).

19.2.5.3. Wind Energy

19.2.5.3.1. Stage of development

The technology related to grid-connected wind turbines has become commercially available and mature. The most successful commercial wind turbines have installed capacities of up to 600 kW. A new generation of machines in the 1 MW size range and above is now being investigated. At the end of 1993, the global installed capacity of high-efficiency wind turbines was 3,100 MW, of which approximately 1,700 MW is in the Americas and 1,200 MW in Europe. While many different designs are in use, the "stock average" technology consists of three-bladed, horizontal-axis machines operating at near-fixed rotation speed. In 1993, the global new installation of wind energy was on the order of 550 MW; the annual manufacturing capacity was over 1,000 MW. This capacity could increase rapidly due to the decentralized structure of production in the wind power industry. Technical availability (the capability to operate when the wind is higher than the starting wind speed of the machine) is now typically 95–99%. Small-scale applications of wind energy such as water pumping, battery charging, and stand-alone electricity supply systems also are being developed (Cavallo *et al*., 1993; WEC, 1994; Sørensen, 1988).

Methods for evaluating wind resources have improved (Troen and Petersen, 1989). In several regions, reviews of resources have been carried out, and siting methods are now being employed regularly to identify the most valuable wind turbine sites (Turkenburg, 1992).

19.2.5.3.2. Technology development

To decrease the cost of electricity, new generations of wind turbines are bigger than current turbines. The reduction of the blade number to two and the introduction of cost-effective power electronic systems to allow for variable-speed operation may further reduce costs.

Intermittent wind power on a large grid can contribute an estimated 15–20% of annual electricity production without special arrangements (see also Section 19.2.6.1). In large utility systems with a small fraction of wind power, savings in fuels and emissions are approximately proportional to the average wind energy input. Employing the so-called loss-of-load-expectation method, the capacity value is typically found to be close to that of a conventional thermal plant with the same energy output at low levels of wind power penetration (supply fraction) and to decline with increasing penetration (van Wijk, 1990; Tande and Hansen, 1991; Grubb and Meyer, 1993). Energy storage facilities probably will be integrated into the utility system, which would allow efficient utilization of wind energy at high penetrations. The wind energy and the storage facility together may supply "firm" power actually substituting for baseload power (Cavallo, 1995; Cavallo and Keck, 1995).

19.2.5.3.3. Economy

The present stock average cost of energy from wind power is approximately 10¢/kWh, although the range is wide. By 2005 to 2010, wind power may be widely competitive with fossil and nuclear power (IAEA, 1991).

A study by Godtfredsen (1993) on new, commercially available wind-power technology gives the distribution of investment cost and the cost of energy. For average new technology, this study shows investment costs of $1,200/kW and electricity production costs of 6¢/kWh. For the best new technology, the figures are $900/kW and 5.5¢/kWh, respectively. The figures are based on an average windspeed of 10 m/s at 10 m above ground level, using single machines or small groups of machines, and do not include long-range transmission costs. Costs could be significantly lower for large wind farms.

The average annual windspeed on the site strongly affects the cost of energy. As a rule of thumb, the wind turbines' production increases with the windspeed to the third power, and the cost of energy decreases accordingly. Wind turbines at very windy sites (for example, coastal regions in northwest Europe) produce electricity at a total cost of 4.0–4.5¢/kWh. Some Danish utility-owned turbines produce electricity at 4.5¢/kWh (Elsamprojekt, 1994).

One set of projections of future costs is presented in Table 19-5. For comparison, Cavallo *et al*. (1993) project a cost of 3.2¢/kWh for 2020, assuming a wind turbine hub height of 50 m, an average wind speed of 5.8 m/s at 10 m, a 6% discount rate, and a useful equipment life of 25 years.

The payback time of the energy invested (energy balance) in the production of the wind turbine is less than one year for average new technology (see Table 19-5).

19.2.5.3.4. Markets

Formulated political goals for the next 20–30 years add up to 150 TWh_e global annual generation. The potential is considerably higher and could be further exploited (see Table B-4 in Chapter B). For example, the World Energy Council presents a "Current

Table 19-5: *Development of wind energy technology: technology level and characteristics, energy payback time for wind turbine, cost of electricity, and barriers to widespread dissemination. Assumptions include discount rates of 6 and 10%, average windspeed at 10 m altitude of 5.5 m/s (roughness class 1), and useful lifetime of 20 years. All costs are in 1990 US$. External costs and CO_2 emissions are not included.*

Technology Level	**Technology Characteristics**	**Energy Balance (months)**	**Direct Cost (¢/kWh)** 6%	10%	**Institutional Barriers**
Stock Average, 1975–90	Three-bladed, induction generator	12	10		kWh-cost
Average New Technology, 1993	Three-bladed, induction generator	9	6	7.4	Cost, public acceptance
Best New Technology, 1993	Three-bladed, induction generator	9	5	6.3	Public acceptance
Near-Term Technology, 2003	Three-bladed, variable speed	6	4.2	5.4	Public acceptance, load management
Long-Term Technology, 2020	Two-bladed, variable speed, flexible structure	6	3.4	4.3	Load management, transmission

Policy Scenario" and an "Ecologically Driven Scenario"—the latter showing an annual production of electricity from wind turbines of close to 1,000 TWh_e in the year 2020 (Van Wijk *et al.*, 1993; WEC, 1994), which is close to 8% of the global annual electricity consumption in 1990.

19.2.5.3.5. Public acceptance

Countries with large numbers of operating wind turbines sometimes experience strong public resistance before installation. Local values, circumstances, and decisionmaking procedures influence the degree of resistance to the noise of turbines, the visual impact on the landscape, the disturbance of wildlife (birds), and the disturbance of telecommunications (Arkesteijn and Havinga, 1992). In areas of Britain and Denmark with wind turbines installed, 70–85% of the citizens are supportive or not concerned (Carver and Page, 1994; DTI, 1993). The little evidence of the impact of turbines on wildlife (Grubb and Meyer, 1993) suggests that it is generally low and species-dependent (Still *et al.*, 1994). Case stories of birds killed by wind turbines have initiated new research that should illuminate the matter. At a 269-unit wind farm near Tarifa, Spain—on the main western bird-migration route between Africa and Europe—dozens of dead birds have been found (*Windpower Monthly*, February 1994). Closure and covering of a nearby waste pit is expected and intended to reduce bird mortality. New blades and gearboxes may generate less noise. Colors, tower type and shape, and number of blades are being studied to improve the appearance of turbines. Still, there are likely to be some sites of exceptional landscape or historic value where wind power plants cannot be accepted.

Experience also indicates how public acceptance can be secured. The most important means are information about wind energy's environmental benefits, a proactive style of communication, and considerate conduct by developers and authorities when wind-farm sites are identified and claimed for wind energy use (Turkenburg, 1992). In Denmark and the Netherlands, private/cooperative ownership of wind turbines also has helped in achieving public acceptance.

19.2.5.4. Solar Electric Technologies

Direct conversion of sunlight to electricity can be achieved by photovoltaic and solar thermal electric technologies.

19.2.5.4.1 Photovoltaic technologies

Photovoltaic (PV) devices made of layers of semiconductor materials convert sunlight directly into electricity. Since they are modular, create no pollution in operation, can be operated unattended, and require little maintenance, PV systems often will be deployed at small scales and close to users. PV technologies can be deployed virtually anywhere—even in areas with frequent cloudiness. Centralized and distributed grid-connected power generation is most important for GHG emissions reductions. Small-scale applications for rural electrification for lighting, water pumping, refrigeration, and educational purposes are important for development but are less significant for GHG emissions reductions.

For several years, PV has been competitive in stand-alone power sources remote from electric utility grids. It has not been competitive, however, in bulk electric grid-connected applications. System capital costs are $7,000–10,000/kW; the corresponding electricity cost is 23–33¢/kWh, even in areas of high insolation (2,400 kWh/m^2/yr). New fossil fuel power plants cost less than 5¢/kWh. PV costs are declining, however. PV module prices in 1992 were one-tenth those in 1976 as cumulative production increased 1,000-fold. There are good prospects for continuing cost reduction, as indicated in Table 19-6 (Kelly, 1993; Ahmed, 1994; INEL *et al.*, 1990; WEC, 1994).

Two basic types of PV devices are flat-plate systems that convert both direct and diffuse radiation; and concentrators that must have direct radiation to work effectively and use mirrors or lenses to concentrate the incident light onto a small area equipped with solar cells. The prospects for major cost reductions are especially good for thin-film PV modules that would be used in flat-plate devices (Carlson and Wagner, 1993; Zweibel and Barnett, 1993) and for sun-tracking, concentrating systems (Boes and Luque, 1993).

Thin-film devices: The active PV materials for thin-film devices are layers 1- to 2-μm thick deposited on appropriate substrate materials (e.g., glass plates) for modules with areas of about 0.5 m^2 or more. Although they are less efficient than the more conventional, thick crystalline silicon devices, the small quantities of active materials required imply a potential for achieving very low costs at acceptable efficiencies (Carlson and Wagner, 1993; Zweibel and Barnett, 1993).

Amorphous silicon (a-Si) is the only thin-film technology established commercially, accounting for 27% of world PV sales of about 63 MW in 1993. The 5% efficiencies of commercial modules are far from the long-term goal of 15% for flat-plate devices (Kelly, 1993). Stabilized efficiencies of 10% have been realized for submodules (Zweibel, 1995). The relative ease of manufacturing a-Si modules (Carlson and Wagner, 1993) may make it possible to design cost-effective a-Si systems that are integrated into building rooftops, windows, and walls. PV electricity generation could become an integral part of the living environment (Hill *et al.*, 1994; Humm and Toggweiler, 1993; Strong and Wills, 1993).

How much it will be feasible to increase a-Si module efficiencies is uncertain. With the current glow-discharge deposition technique, a-Si films must be made ultrathin to compensate for the initial degradation of efficiency following exposure to light. This Staebler-Wronski effect (Carlson and Wagner, 1993) makes efficiencies greater than about 10% difficult. Light-induced efficiency degradation may not be a problem for an alternative hot-wire deposition technique (Vanecek *et*

Table 19-6: *Alternative projections of installed photovoltaic system costs (1990 US$).*

Parameter	U.S. DOE Interlaboratory White Paper[1] Business As Usual	Intensification of RD&D	Williams and Terzian[2] Business As Usual	Accelerated Development	Zweibel and Luft[3] Thin-Film Systems
Installed Capital Cost ($/kW)					
2000	3820	2540	4470	3610	3500
2005	–	–	3500	2170	2000
2010	2290	1770	2770	1520	1000
2020	1530	1250	1850	1060	800
2030	1280	1010	–	–	640
Busbar Cost in 2010[4] (¢/kWh)					
@ 2400 kWh/m^2/yr	7.6	5.9	9.1	5.0	3.5
@ 1800 kWh/m^2/yr	10.1	7.8	12.1	6.7	4.6
@ 1200 kWh/m^2/yr	15.1	11.8	18.1	10.0	6.9
Busbar Cost in 2020[4] (¢/kWh)					
@ 2400 kWh/m^2/yr	5.1	4.2	6.1	3.5	2.7
@ 1800 kWh/m^2/yr	6.8	5.6	8.1	4.7	3.6
@ 1200 kWh/m^2/yr	10.2	8.4	12.2	7.1	5.3
Busbar Cost in 2030[4] (¢/kWh)					
@ 2400 kWh/m^2/yr	4.2	3.3	–	–	2.2
@ 1800 kWh/m^2/yr	5,6	4.5	–	–	3.0
@ 1200 kWh/m^2/yr	8.4	6.7	–	–	4.4

[1]Idaho National Engineering Laboratory *et al*., 1990.
[2]Williams and Terzian, 1993.
[3]Zweibel and Luft, 1993.
[4]Calculated assuming 6% discount rate.

al., 1992; Haage *et al*., 1994), but it remains to be demonstrated whether high efficiencies can be achieved with this technique (Zweibel, 1995). There are good prospects of achieving the 15% goal with at least one thin-film technology. Besides a-Si, two polycrystalline technologies show great promise: $CuInSe_2$ and CdTe (Zweibel and Barnett, 1993). Although there has not been as much development effort focused on these as for a-Si, progress has been rapid. Between 1977 and 1994, efficiencies of laboratory cells have increased from 6% to about 17% for $CuInSe_2$ and from 8% to about 16% for CdTe (Zweibel, 1995), without serious stability problems. Stable efficiencies for submodules about 0.1 m^2 in size already are comparable to or greater than what has been realized with a-Si.

Because of its modularity, PV technology is a good candidate for cost-cutting through “learning-by-doing” as well as technological innovation (Cody and Tiedje, 1992; Tsuchiya, 1989). A design exercise exploring what can be achieved by mass-producing near-term $CuInSe_2$ technology (Bradaric *et al*., 1992) generated estimates that a 50-MW power plant based on 1995 $CuInSe_2$ technology would have an installed cost of $2300/kW, corresponding to a generation cost of about 8¢/kWh in areas with good insolation, and the value of the electricity to the utility would be comparable if the plant were sited where the output is well-correlated with peak electrical demand.

In the transition period to large-scale PV development, the value of PV in grid-connected applications often can be enhanced by locating the PV system close to users—at utility substations and on commercial and residential rooftops—instead of in central stations. For such distributed applications in areas where there is a good correlation between PV output and utility subsystem peak demand, the electricity is worth substantially more to the utility than in central-station configurations (Shugar, 1990; Kelly and Weinberg, 1993; Wenger and Hoff, 1995; Hoff *et al*., 1995). Moreover, net system costs could be reduced in configurations where PV modules serve dual purposes (for example, being roof tiles as well as providing power). Markets for high-value, grid-connected, distributed PV are likely to be large in both the United States and in many developing countries (Williams and Terzian, 1993).

Although the long-term prospects for thin films are much harder to predict than the prospects for cost-cutting through learning-by-doing, thin-film researchers tend to be optimistic. Thin-film program management at the National Renewable Energy Laboratory in the United States projects that installed system costs will fall to about $1,000/kW by 2010 and ultimately to $600–700/kW (Table 19-6; Zweibel and Luft, 1993).

Concentrating, tracking PV technology: Much higher efficiencies can be achieved with crystalline PV technologies than is possible at present with thin films. Already, efficiencies of 28% for crystalline silicon and 34% for mechanically stacked gallium arsenide/gallium antimony multijunction cells have been achieved, and higher efficiencies are expected. Although such cells are much more costly to make than thin films, the higher costs can be offset by using devices that concentrate the sun's rays by a factor of anywhere from 2 to 1,000. The contribution of the cell cost to the module cost is reduced by this concentrating factor, and the concentrating device is expected to be much less costly per unit area than the cell.

Bradaric *et al*. (1992) have designed a 50-MW_e power plant based on the use of expected 1995-vintage concentrating technology (27.4%-efficient cells used in a two-axis tracking concentrator) brought to technological maturity. Their estimated installed cost is about \$3,200/kW for mass-produced modules; the corresponding cost of electricity in a sunny area would be about 9¢/kWh. Whereas high-concentration ratio devices would be most suitably deployed in central-station configurations, low-concentration ratio devices—for example, flat-plate, thin-film devices—would be suitable for many distributed applications, both grid-isolated and grid-connected.

Life-cycle analysis: Life-cycle issues of concern for PV systems are energy payback time, toxic emissions, and the use of scarce materials.

The energy payback time is the ratio of the primary energy required to manufacture 1 m^2 of module plus balance-of-system (support structure, wiring, installation) for the power plant to the rate of primary fossil energy avoided by the electricity production with 1 m^2 of module. Most studies have focused on energy inputs for modules and have found that the energy payback time is strongly correlated with the amount of active PV material used. For silicon devices, the payback time is an estimated 5–10 years for monocrystalline, 3–5 years for polycrystalline, and 0.5–2 years for a-Si modules (von Meier, 1994). For monocrystalline and polycrystalline power plants, the payback is dominated by the energy required to make cells.

For thin-film devices, the difference between current and future technology is expected to be large. The payback for a-Si modules is estimated (for global average insolation of 1,700 $kWh/m^2/yr$) to be 2.5 years for 6%-efficient modules and generally pessimistic conditions versus 0.5 years for 10%-efficient modules and "base case" conditions (van Engelenburg and Alsema, 1994). Assuming future 15%-efficient modules, paybacks are expected to be even lower for polycrystalline modules: 1.6 months for CdTe and 4 months for $CuInSe_2$ (Alsema and van Engelenburg, 1992). For grid-connected systems, the balance-of-system is estimated to contribute an additional 1.8 years with today's technology but only 0.6 years with future systems using 10%-efficient modules (Hagedorn, 1989).

Emissions: Although PV devices emit no pollution in normal operation, some systems involve the use of toxic materials, which can pose risks in manufacture, use, and disposal. Life-cycle risks posed by silicon PV systems are small (Sørensen and Watt, 1993), but the potential hazards posed by the cadmium in CdTe and the selenium in $CuInSe_2$ devices warrant scrutiny—especially air emissions resulting from fires involving rooftop systems and incineration of unrecycled module waste. Such life-cycle emissions per kWh generated would be comparable to those from modern coal-fired power plants (Alsema and van Engelenburg, 1992).

Resources: There are no resource constraints for silicon PV systems. Although thin-film polycrystalline devices use only tiny amounts of active material, some materials are scarce. Of particular concern are the tellurium used in CdTe and especially the indium used in $CuInSe_2$ systems. Recycling might be required in order for these technologies to play major roles in the global energy economy (Alsema and van Engelenburg, 1992).

The societal cost of research, development, and commercialization: PV is the furthest of the renewable energy technologies from being commercially attractive in large-scale applications. How fast costs come down in the future depends on the level of the societal commitment to develop the technology. Williams and Terzian (1993) conclude that it would be worthwhile to accelerate rapidly the pace of development via intensification of the R&D effort and market incentives because the public-sector costs involved are expected to be small compared with the direct societal benefits, measured as the present value of reduced future consumer expenditures on electricity. Williams and Terzian (1993) estimate the public-sector subsidy to develop 400 GW_e of installed PV capacity worldwide by 2020 to be \$1 billion/yr for more R&D in the early years, plus a present value of \$3.3 billion for future market incentives. These estimates are similar to those made by the World Energy Council in estimating what would be required to commercialize PV technologies: a market stimulation incentive of \$2.5–4.0 billion, plus another \$5 billion for R&D (WEC, 1994). These costs are very small compared with the costs of commercializing fossil and nuclear technologies, largely because of the small scale of the technology.

19.2.5.4.2. Solar thermal-electric technologies

Solar thermal-electric technologies use mirrors or lenses to concentrate the sun's rays onto a heat exchanger, where a heat-transfer fluid is heated and used to drive a conventional power-conversion system. Applications for solar thermal-electric systems range from central-station power plants to modular, remote power systems. Such systems can be hybridized to run on both solar energy and fossil fuel; some systems contain integral thermal energy storage, allowing dispatchable, solar-only operation. These systems use only direct rays from the sun and are best located in regions of high sunlight intensity. Solar thermal-electric systems have the long-term potential to provide a significant fraction of the world's electricity and energy needs (WEC, 1994; Brower, 1993).

Between 1984 and 1990, nine utility-scale solar thermal power plants—cumulatively over 350 MW_e—were constructed in southern California using solar parabolic-trough technology driving a steam turbine in a hybrid configuration co-fired with natural gas. Developers of this technology in Europe and the United States are pursuing new power plant projects in several developing countries that could result in several hundred megawatts of new installations before the year 2000. In Australia, a tilted, polar-tracking-oriented, parabolic-trough system, with selective surfaces improving absorption and reducing losses and low concentration for higher diffuse radiation acceptance, is being developed that incorporates a storage system to allow high solar capacity factors (Mills and Keepin, 1993).

A solar central receiver—also called a "power tower"—uses a field of sun-tracking mirror assemblies to concentrate sunlight onto a tower-mounted receiver, where a circulating fluid is heated and used to produce power. Power towers typically contain cost-effective thermal energy storage and are intended as central-station power plants for peaking and intermediate load applications in 100–200 MW_e plant sizes (Hillesland and De Laquil, 1988; Hillesland, 1988). The technology is in the demonstration phase and could enter the utility-generation marketplace in the second half of the 1990s. In the United States, the 10-MW_e Solar Two Project, which will demonstrate nitrate salt receiver and storage technology, is scheduled to be operating by 1995 (Von Kleinsmid and De Laquil, 1993). A European industry consortium is planning to develop a 30-MW_e demonstration plant in Jordan using a volumetric air receiver and ceramic storage (De Laquil *et al*., 1990; Phoebus, 1990; Haeger *et al*., 1994); this plant could be operational by 1997. In Israel, the Weizmann Institute is developing a pressurized volumetric air receiver that could be used to drive a gas turbine or combined-cycle power plant. Initial receiver testing was encouraging, and scale-up and system integration are now being addressed (Karni, 1994).

Parabolic dishes supplying the external heat for a Stirling heat engine have achieved a maximum net solar-to-electric conversion efficiency of 29.4% and an average daily net efficiency of 22.7% (Washom, 1984). Dish-engine system modules range from 2 to 25 kW, and several companies in the United States and in Europe are developing systems for remote applications as well as grid-connected, distributed-power application (Kubo and Diver, 1993). In the United States, design validation systems are currently undergoing field tests; early commercial systems are expected to be available in 1996. The Australian National University has developed a 50-kW dish concentrator system driving a small, ground-mounted steam power plant (Kaneff, 1994; Stein, 1994).

Table 19-7 lists projections for cost and performance of each solar thermal-electric technology (De Laquil *et al*., 1993). Parabolic-trough technology has achieved significant cost reductions and current plants have energy costs of 9–13¢/kWh in the hybrid mode. Power towers have significantly lower projected energy costs, 4–6¢/kWh, which can be achieved at production rates of 200 MW/yr without technological breakthroughs. These costs must be proven at commercial scale, however. The thermal-storage feature of the nitrate salt power-tower technology allows electricity to be generated when it is most valuable and, in principle, allows annual solar-only capacity factors of 100%. With high-volume manufacturing, dish-engine systems have a cost potential as low as 5.5¢/kWh in a solar-only mode. They also can be hybridized using most gaseous or liquid fuels to provide continuous operation. In general, all solar thermal-electric technologies require the installation of a few hundred MW_e of systems before they reach their expected cost targets.

Integrated solar, combined-cycle plant configurations, which are being developed for both parabolic-trough and power-tower technology, promise to lower costs significantly for early commercial plants. Capital costs are in the range of $1,000–1,500 per kW, and electricity costs have been calculated to be within 0.5¢/kWh of conventional, natural gas-fired, combined-cycle power plants; the annual solar fraction (the share of demand covered by solar) for these integrated, combined-cycle configurations typically is 20% or lower. Because they reduce both the market entry cost and risk hurdles, such hybrids may lead to earlier introduction of commercial plants. Higher-solar fraction plants can be built as the cost of solar-based electricity approaches the cost of natural gas-based electricity.

Land use, water consumption, compatibility with desert species, and aesthetics are the principal environmental considerations. Because large plants will be best located in desert regions, water consumption is likely to be the most serious environmental issue.

In addition to electricity production, solar thermal systems can provide high-temperature process heat, and central receivers can be used to process advanced fuels and chemicals—for example, hydrogen—which may enhance their long-term potential.

19.2.5.5. Solar Thermal Heating

Solar thermal systems provide heating and hot water for domestic, commercial, or industrial uses (Duffie and Beckman, 1991). Solar cooking and solar cooling cycles are described in Sørensen (1979a). Simple solar thermal systems comprise:

- *Passive solar thermal systems*: Controlled solar collection through building design and the use of proper materials and practices, including smart windows, solar walls, and evaporative cooling (see Chapter 22).
- *Active solar thermal collectors*: Available designs range from unglazed, uninsulated plastic collectors for temperatures just above the ambient temperature to evacuated concentrating collectors for temperatures above 200°C. Flat-plate collectors based on a thermosyphon principle or with forced circulation for 60–80°C dominate at present.
- *Systems for use with solar thermal technologies:* Energy storage in building materials, water (including aquifers), rocks, and soil for individual houses and community systems (Dahlenbäck, 1993), and consideration of fuel backup and proper system management.

Table 19-7: *Levelized energy cost projections.*[1]

	Parabolic Trough			Central Receiver				Dish-Stirling		
	80 MW_e	80 MW_e	200 MW_e	100 MW_e	200 MW_e	200 MW_e	200 MW_e	3 MW_e per year	30 MW_e per year	300 MW_e per year
				first plant	*first plant*	*baseload*	*advanced receiver*	*early remote market*	*early utility market*	*utility market*
Time Frame	Present	1995-2000	2000-2005	1995	2005	2005-2010	2005-2010	1995-2000	2000-2005	2005-2010
Capital Cost Range ($/$kW_e$)	3500–2800	3000–2400	2400–2000	4000–3000	3000–2225	3500–2900	2500–1800	5000–3000	3500–2000	2000–1250
Collector System Typical Cost ($/$m^2$)	250	200	150	175–120	120–75	75	75	500–300	300–200	200–150
Annual Solar-to-Electric Range[2] (%)	13–17	13–17	13–17	8–15	10–16	10–16	12–18	16–24	18–26	20–28
Enhanced Load Matching Method	25% natural gas	25% natural gas	25% natural gas	thermal storage	thermal storage	thermal storage	thermal storage	solar only	solar only	solar only
Solar Capacity Factor Range (%)	22–25	18–26	22–27	25–40	30–40	55–63	32–43	16–22	20–26	22–28
Annual O&M Cost Range (¢/kWh)	2.5–1.8	2.4–1.6	2.0–1.3	1.9–1.3	1.2–0.8	0.8–0.5	1.2–0.8	5.0–2.5	3.0–2.0	2.5–1.5
Solar LEC Range (¢/kWh)	16.7–11.8	17.2–9.8	11.7–7.9	16.1–8.0	10.1–5.8	6.5–4.6	8.2–4.5	32.8–14.6	18.6–8.8	10.6–5.5
Hybrid LEC Range (¢/kWh)	13.0–9.3	13.5–7.9	9.3–6.5	–	–	–	–	–	–	–

[1] From De Laquil *et al*. (1993), which compiled these data from several sources. The levelized energy cost (LEC) calculations are based on a 6% real discount rate; the fixed charge rate for capital is 7.8%.
[2] Typical southwest U.S. site.

Domestic hot water currently is the most important application. For one household, the typical collector area is 3–6 m^2, with a 300-liter water-storage tank. Because the available roof space generally is not a limiting factor, system efficiency is the result of a cost/benefit optimization for the entire system. A typical annual average value is 30–40%. The solar fraction is limited by the seasonal variation in irradiation levels. In equatorial areas it can be 100%, whereas it does not exceed 50% in high-latitude areas without significant storage.

Investment costs for an installed domestic solar hot-water system for one household range from $600 for a 2-$m^2$ thermosyphon system in the Middle East to $6,000 for a 4-$m^2$ pumped system in northwest Europe. Annual system output varies from 300 to 600 kWh_{th}/m^2. At a real rate of return of 6% (10%), heat costs range from $8 ($14) to $80 ($140) per GJ_{th}. The production and use of domestic solar hot-water systems does not have significant environmental effects. The energy payback time is about one year.

Large numbers of solar thermal collectors are installed, notably in Europe, Asia, and North America. An estimated 20–30 million m^2 deliver 40–60 PJ/yr (Nitsch, 1992). The technical potential is much larger. The installed capacity varies greatly, even between countries with similar climate and geography. Thus, attention to implementation issues may help—for example, the adjustment of building codes to accept solar collectors. Several countries offer subsidies in view of the environmental advantages of solar thermal systems (Gregory *et al*., 1993). Demonstration systems for space heating with up to 7,500 m^2 of collectors have been realized together with seasonal heat storage (Dalenbäck, 1993).

Future prospects include an expected lowering of cost. The main stock of collectors have absorbers of steel with selective coating, glass cover, and aluminum frame and backplate, plus insulating material such as mineral wool. Cheaper constructions use plastic absorbers (polypropylene ribbons), polycarbonate covers, and fiber backplates. Another development is high-efficiency evacuated tubes providing two to three times higher annual collection per unit area. Costs are expected to decline due to higher volume, more efficient manufacturing processes, and reduced installation costs. An important topic for further R&D is the optimization of heat distribution systems with contributions from different heat sources (cogeneration, heat pumps, solar energy, and storage).

19.2.5.6. Geothermal and Ocean Energy

The two remaining renewable sources of energy are geothermal energy and ocean energy.

19.2.5.6.1. Geothermal energy

Geothermal energy resources are made up of both nonrenewable and renewable parts: The nonrenewable is stored from the time of the Earth's formation, and the renewable is due to the isotopic decay of radioactive elements in the Earth's interior.

Electricity is generated from geothermal energy in 21 countries. Commercial production on the scale of hundreds of MW has been undertaken for more than three decades, both for electricity generation and direct heat utilization. The installed capacity is nearly 6,300 MW_e. Four developing countries produce more than 10% of their total electricity from geothermal (El Salvador, 18%; Kenya, 11%; Nicaragua, 28%; the Philippines, 21%). The cost of electric generation is estimated to be around 4¢/kWh_e. Direct use of geothermal water (space heating, horticulture, fish farming, industry, and/or bathing) occurs in about 40 countries; 14 countries have an installed capacity of more than 100 MW_{th}. The overall installed capacity for direct use is about 11,400 MW_{th}, and the annual energy production is about 36 TWh_{th} (Fridleifsson and Frecston, 1994). The production cost for direct use is highly variable but commonly under 2¢/kWh_{th}. In addition, low-temperature heat stored in soil, water, and air can be upgraded by heat pumps and used for space heating and hot water.

Various emissions are associated with geothermal energy, including CO_2, hydrogen sulfide, and mercury. Advanced technologies are almost closed-loop and have very low emissions (WEC, 1994).

In recent decades, installed geothermal energy capacity has grown 10% a year for direct uses and from 8–17% for power generation. The growth is expected to continue but at slightly lower rates (Fridleifsson and Frecston, 1994).

Geothermal energy reserves that might be exploited in the next 2 decades are estimated to be 500 EJ, mostly relatively low-grade heat. Most geothermal systems are hydrothermal, but geopressured, magma, and hot dry rock systems are in the demonstration stage (Palmerini, 1993). Although it can make substantial local contributions in some areas, geothermal energy is unlikely to contribute more than 2% of total global energy requirements, even if hot dry rock geothermal technology is developed at an accelerated rate (Palmerini, 1993).

19.2.5.6.2. Ocean energy

Energy is stored in the tides, waves, and thermal and salinity gradients of the world's oceans. Although the total energy flux of each of these renewable resources is large, only a small fraction of their potential is likely to be exploited in the next 100 years. Ocean energy is spread over a wide area and would require large and expensive plants for collection, and much of the energy is available only in areas far from centers of consumption.

Tidal energy, which uses barrages at sites having a high tidal range, has considerable technical potential (Cavanagh *et al.*, 1993). Many sites with the most potential, however, also have been considered to be of great environmental significance—for example, some are bird habitats (Rodier, 1992; WEC, 1994).

The technology to use wave energy is in its infancy. Near-shore devices are likely to be developed first, but their applicability and potential are limited. Most wave energy is offshore. Because of technological problems and high costs, more powerful large-wave offshore energy plants are unlikely to be deployed for a few decades. Ocean thermal energy conversion (OTEC), which is currently in the prototype stage, is very costly and largely restricted to tropical locations (Cavanagh *et al.*, 1993).

19.2.6. Energy Systems Issues

System design and management issues are important for many new energy technologies that can significantly reduce GHG emissions. The most important are the management of intermittent power generation; the choice of a mix of renewable, fossil, and nuclear electric-generating technologies; the use of electricity transmission technologies; and the use of hydrogen or hydrogen-rich energy carriers.

19.2.6.1. Managing Intermittent Power Generation

Intermittent power-generating supplies can be managed by new load-management techniques; an appropriate mix of dispatchable generating capacity for backing up intermittent sources; interconnecting grid systems; and mechanical, electrochemical, thermal, or other forms of storage (Sørensen, 1984).

If energy users knew the current and expected availability of intermittent energy sources and associated energy prices, they might change their patterns of energy demand. Price signals and related information could be transmitted to users through power lines or other information channels so they could plan their use of electricity accordingly. This kind of demand management can be automated by using intelligent appliances and equipment responding to signals received through the grid according to selections programmed by users.

Energy suppliers might apply transmission planning, including the transfer of electricity over large distances to cope with some of the daily variations of wind and solar energy. The management of interconnected grids could be optimized to allow maximum inputs from variable power sources, as is currently done to make the best use of baseload power plants.

Hydropower plants allow prompt regulation and can back up intermittent energy generators, as can some types of thermal power plants. The ideal thermal complements to intermittent renewable energy plants on grid systems are plants characterized by low unit capital cost (so they can be operated cost-effectively at low capacity factor) and fast response times (so they can adjust to rapid changes in intermittent supply output). Gas turbines and combined cycles satisfy these criteria, but supercritical fossil and nuclear steam-electric plants do not. Thus, nuclear and intermittent renewable power sources are competitive rather than complementary strategies at high grid-penetration levels.

The levels of electricity generation from intermittent sources (for example, from wind turbines or photovoltaic arrays) that can be accepted in a supply system depend strongly on the nature of the system and the measures that manage time variations in load. Typical percentages of wind or solar shares in systems without storage are about 20% for grid systems and up to 50% for large systems with reservoir-based hydro or time-zone variations of loads (Sørensen, 1981, 1987; Grubb and Meyer, 1993; Kelly and Weinberg, 1993).

Short-term storage will ease regulation and possibly improve power quality, but only intermediate and long-term storage will allow large systems to have shares of variable renewable-energy sources that significantly exceed 50% (Jensen and Sørensen, 1984). One important use of storage is to convert a remotely located intermittent electric supply into baseload power to obtain a high level of utilization of electric transmission capacity and thereby reduce the specific cost of long-distance transmission to electric demand centers. The use of compressed-air energy storage (Cavallo, 1995) and even seasonal compressed-air energy storage (Cavallo and Keck, 1995) in conjunction with large wind energy farms has been shown to be an economically promising way to exploit remotely located wind resources.

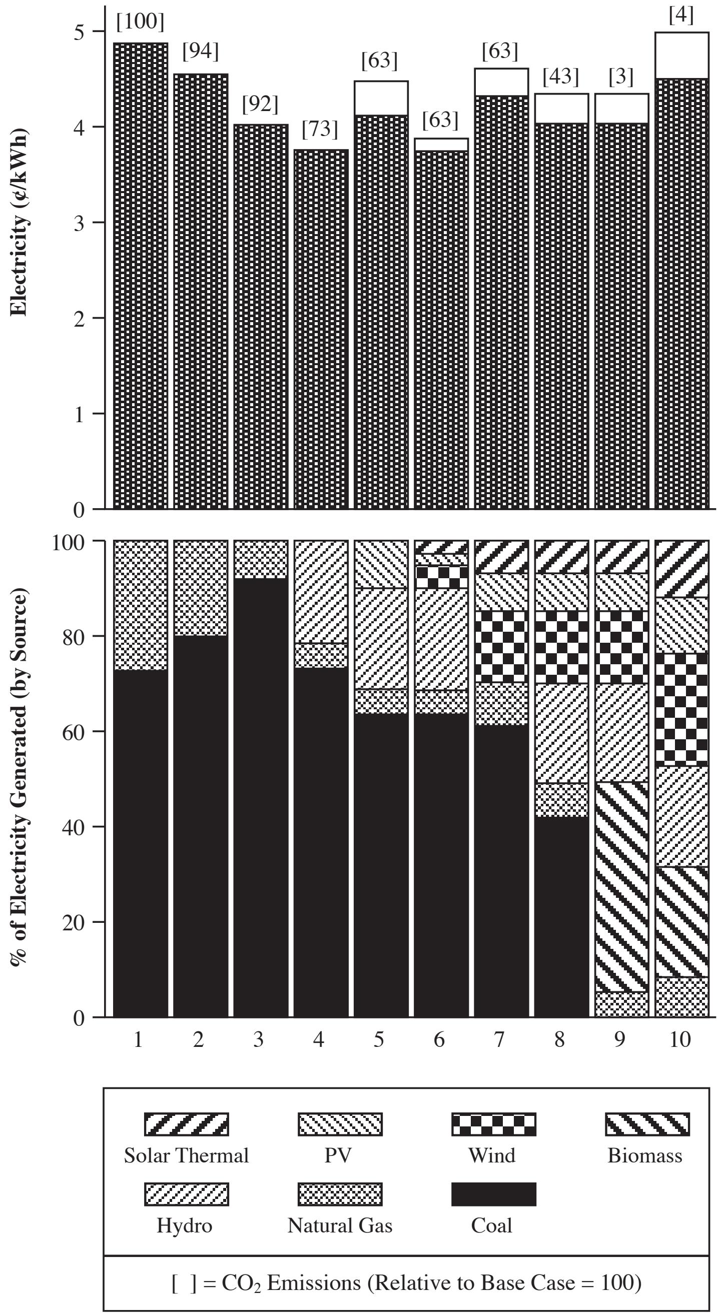
Round-trip efficiencies for storage range from 65–70% for lead-acid batteries, pumped hydro, and compressed air to 95% for superconducting storage (Jensen and Sørensen, 1984). Some storage technologies pose environmental problems that need to be addressed—including metal contamination from batteries and riverbed erosion problems with water surges from hydropower.

19.2.6.2. Electric Power System Characteristics and Costs

In the decades immediately ahead, many renewable electric systems will be introduced in stand-alone configurations remote from electric utility grids and used in connection with small-scale electrical storage and fossil energy backup systems. In the longer term, however, most renewable electric systems will be connected to electric utility grids. Managing grid-connected renewable electric technologies poses new challenges for utilities. Unlike the thermal power plants that utilities are accustomed to managing, intermittent renewable power plants are not dispatchable. Moreover, many of these technologies produce electricity in plants that are much smaller than those used in today's power systems. Scales range from 1 kW_e for some photovoltaic and fuel-cell systems to 25–300 MW_e for biomass systems because the costs per unit of capacity for such technologies will be relatively insensitive to scale. For these systems, the economies of mass-produced standardized units are more important than the economies achievable with large unit sizes. Many of the smaller-scale technologies will be sited not in central-station plants but at or near customers' premises. Some photovoltaic and fuel-cell systems can be operated unattended and installed even at individual houses. Electricity produced from such "distributed power systems" is worth more to the utility than central-station power whenever the electrical output is highly correlated with the utility peak demand, largely because such siting makes it possible to defer transmission/distribution investments (Shugar, 1990; Hoff *et al*., 1995).

New analytical tools are being developed to integrate such technologies into electric utility grids and to value and manage power systems that involve combinations of intermittent and dispatchable power sources. One such tool, the SUTIL simulation model (Kelly and Weinberg, 1993), calculates the average cost of electric generation as the result of an hour-by-hour simulation that takes into account demand, the variable output of intermittent renewable equipment, the load-leveling capabilities of hydroelectric facilities, and the dispatching characteristics of alternative thermal-electric plants. Results of a SUTIL simulation of 10 alternative portfolios for a hypothetical utility—based on assumed values of the demand load profile, insolation, fuel costs, and capital costs—are shown in Figure 19-4.[5] Note that the assumed costs for conventional fuels and technologies, particularly for natural gas and for

[5] Since this SUTIL modeling exercise was carried out, present and projected fuel prices and technology costs have changed significantly. For example, compared to the assumed overnight construction costs of $525/kW and $625/kW for conventional and advanced natural gas combined cycle plants, respectively, combined cycle plants are being installed at present in the U.S. at costs as low as $400/kW. As a sensitivity analysis, the SUTIL model was run again with assumed coal and natural gas prices of $1.3/GJ and $3.2/GJ, respectively [equal to national average prices projected for electric utilities in the U.S. in the year 2010 by the U.S. Department of Energy (EIA, 1995)], with an assumed biomass price of $1.5/GJ [an estimated long-run marginal cost for producing 5 EJ/yr of plantation biomass in the U.S. using biomass production technology projected for the year 2020 (Graham *et al*., 1995)], together with the original SUTIL technology cost assumptions. Although overall generation cost levels are lower with these new fuel price assumptions, the relative costs of alternative investment portfolios differ only modestly from those shown in Figure 19-4. For example, the average generation cost for the updated version of case 9 is 8% higher than for case 4 (3.37¢/kWh vs. 3.12¢/kWh) (Williams, 1995a). Note that differences in marginal costs associated with the introduction of intermittent renewables are significantly greater than is indicated by these average portfolio cost differences.



KEY:
1 = Conventional fossil
2 = Best new fossil
3 = Advanced fossil
4 = Advanced fossil with 21% hydro
5 = Advanced fossil with 10% PV and 21% hydro
6 = Advanced fossil with 10% intermittents and 21% hydro
7 = Advanced fossil with 30% mixed intermittents (three wind sites)
8 = Advanced fossil with 30% mixed intermittents (three wind sites) and 21% hydro
9 = Advanced biomass and gas with 30% mixed intermittents (three wind sites) and 21% hydro
10 = Advanced biomass and gas with 50% mixed intermittents (three wind sites) and 21% hydro

Figure 19-4: *Comparing Investment Portfolios for a Hypothetical Electric Utility*—The average life-cycle cost and relative CO_2 emissions for meeting the annual electricity needs (top) and the fraction of electricity generated by each energy source (bottom) are displayed for alternative configurations of a hypothetical utility. The life-cycle costs were calculated for a 6% discount rate using the SUTIL model (Kelly and Weinberg, 1993). The calculations involved a simulation of the utility that considered the variability of electricity demand and the output of intermittent renewable equipment, the load-leveling capabilities of hydroelectric facilities, and the dispatching of natural gas, coal, and biomass thermal electric plants. The electricity demand profile (that for an actual large utility in northern California) was specified on an hour-by-hour basis throughout the year. The assumed insolation values are for northern California. For the given demand profile, alternative electricity supply portfolios having the same degree of system reliability were constructed. Each portfolio involves specified levels of penetration by intermittent renewable electric and hydroelectric sources, and the model determines the least costly mix of thermal-electric equipment and fuels that would meet the remaining load, assuming alternative levels of technology for the thermal generating equipment and specified 30-year levelized life-cycle fuel prices. For all advanced fossil and renewable energy technologies highlighted in these constructions, it was assumed that R&D is successful in meeting performance and cost goals for the period near 2010. Thirty-year levelized coal, natural gas, and biomass prices were assumed to be \$2.0/GJ, \$4.4/GJ, and \$2.4/GJ, respectively. Assumptions about capital and operations and maintenance costs, and about performance characteristics of alternative technologies, are presented elsewhere (Johansson *et al*., 1993a). For the six cases displayed on the right, the photovoltaic (pv) systems are sited in distributed configurations; the clear segments at the tops of the bars represent the value of distributed pv power to the utility; the net cost is given by the level at the tops of the shaded bars—the gross cost less the distributed pv benefit.

natural gas-fired combined cycles, are significantly higher than currently prevailing values and projections to 2010 for the U.S. For this set of alternative utility investment portfolios:

- All configurations involving advanced technology (cases 3–10) are less costly than the base case (case 1), which involves conventional fossil fuel technologies.
- There is little variation in cost among the advanced technology options, although there are no less costly options than the advanced fossil fuel options (cases 3 and 4).
- The fraction of electrical energy provided by intermittents can rise up to about 30%, without the use of new electrical storage technology, before costs start rising significantly.
- At high levels of penetration of intermittent renewables, baseload thermal power becomes less important and load-following and peaking power become more important.
- The advanced fossil fuel options offer relatively modest reductions in CO_2 emissions.
- The option offering the greatest reduction in CO_2 emissions [case 9, involving biomass for baseload power and a 30% contribution from intermittent renewables and for which emissions are only 4% of those for the least costly case (case 4)] has an average generation cost that is only 7% higher than for the least costly case.

Although costs for technologies that are not yet commercially available cannot be known precisely, it is plausible—on the basis of what is presently known about the prospective costs of advanced renewable and fossil fuel electric-generating technologies—that in the early decades of the next century, utility planners will be able to assemble alternative electric power systems (involving substantial contributions from renewable energy sources) that generate very low CO_2 emissions. These judgments are based on the assumption that various promising renewable-energy technologies will be targeted for R&D and commercialization programs. At the same time, of course, advances will continue to be made in fossil fuel technologies. In many cases, it will be difficult to provide electricity at lower direct cost than with fossil fuels (for example, because both coal and biomass will be able to exploit the same basic advances in gas turbine and fuel-cell conversion technologies).

19.2.6.3. Electricity Transmission Technology

For transporting electric power over more than about 700 km, DC transmission at high voltage (500 to 1,000 kV) via either overhead lines or underwater cables is less costly than AC transmission. Ohmic losses amount to about 4% of the energy transmitted per 1,000 km, while losses associated with DC/AC conversion amount to about 0.6–0.8% per station. Typically, DC transmission increases the cost of electricity about 7% for a 1,000-km line. The low losses and relatively low costs of long-distance DC transmission make it feasible to transport solar power across multiple time zones and to exploit good hydropower (Moreira and Poole, 1993), wind (Cavallo, 1995), and solar power resources that are remote from demand centers. High transmission capacity utilization can be realized with intermittent renewable resources when used in conjunction with compressed air or other energy-storage schemes (Cavallo, 1995).

19.2.6.4. A Long-Term Electricity/Hydrogen Energy System

Since it was first introduced, electricity has accounted for a growing share of the energy carriers used in the energy economy—a trend that is expected to continue. For the longer term, hydrogen is another high-quality energy carrier that society might adopt for large-scale applications. Both electricity and hydrogen offer good prospects for simultaneously dealing with the challenges facing the energy system in the 21st century—local, regional, and global environmental challenges, as well as security of energy supply (Marchetti, 1989; Rogner and Britton, 1991; Leydon and Glocker, 1992). Both are clean, versatile, and easy to use and can be derived from a wide range of primary energy sources. Because of their very different characteristics, hydrogen and electricity would have complementary roles in the energy economy. Hydrogen can be stored in any quantity, but electricity cannot (though this could change if high-temperature superconductivity could be successfully developed). Electricity can transmit energy without moving material; hydrogen cannot. Hydrogen can be a chemical or material feedstock; electricity cannot. Electricity can process, transmit, and store information; hydrogen cannot.

Hydrogen can be produced from any fossil fuel or from biomass via thermochemical conversion and from any electricity source via electrolysis. Conversion to hydrogen and sequestration of separated CO_2 makes it possible to use fossil fuels with modest life-cycle CO_2 emissions (see Sections 19.2.3.2 and 19.2.3.3). Emissions from the production of hydrogen from biomass grown on a sustainable basis would be especially low and negative if the separated CO_2 were sequestered. For the foreseeable future, thermochemically derived hydrogen will be much less costly than electrolytic hydrogen, even taking into account the costs of sequestering the separated CO_2 (see Figure 19-5).

As is the case for any synthetic fuel, hydrogen generally will cost more to produce than conventional hydrocarbon fuels. Natural gas-derived hydrogen (the least-costly option for at least the next couple of decades) delivered to consumers is likely to be much more costly than gasoline, on a dollar per GJ basis—50% higher for energy prices expected for the United States in 2010 (see Figure 19-5). However, this cost penalty does not imply that hydrogen would not be competitive. The choice of energy carrier, its price, and its source are of little concern to the consumer. The consumer cares about the quality and cost of the energy services provided (Scott, 1993). Just as electricity is competitive as an energy carrier—even though it is much more expensive than coal, oil, or natural gas—high-cost hydrogen could be competitive if the market were to place a high value on hydrogen. It would be difficult for hydrogen to

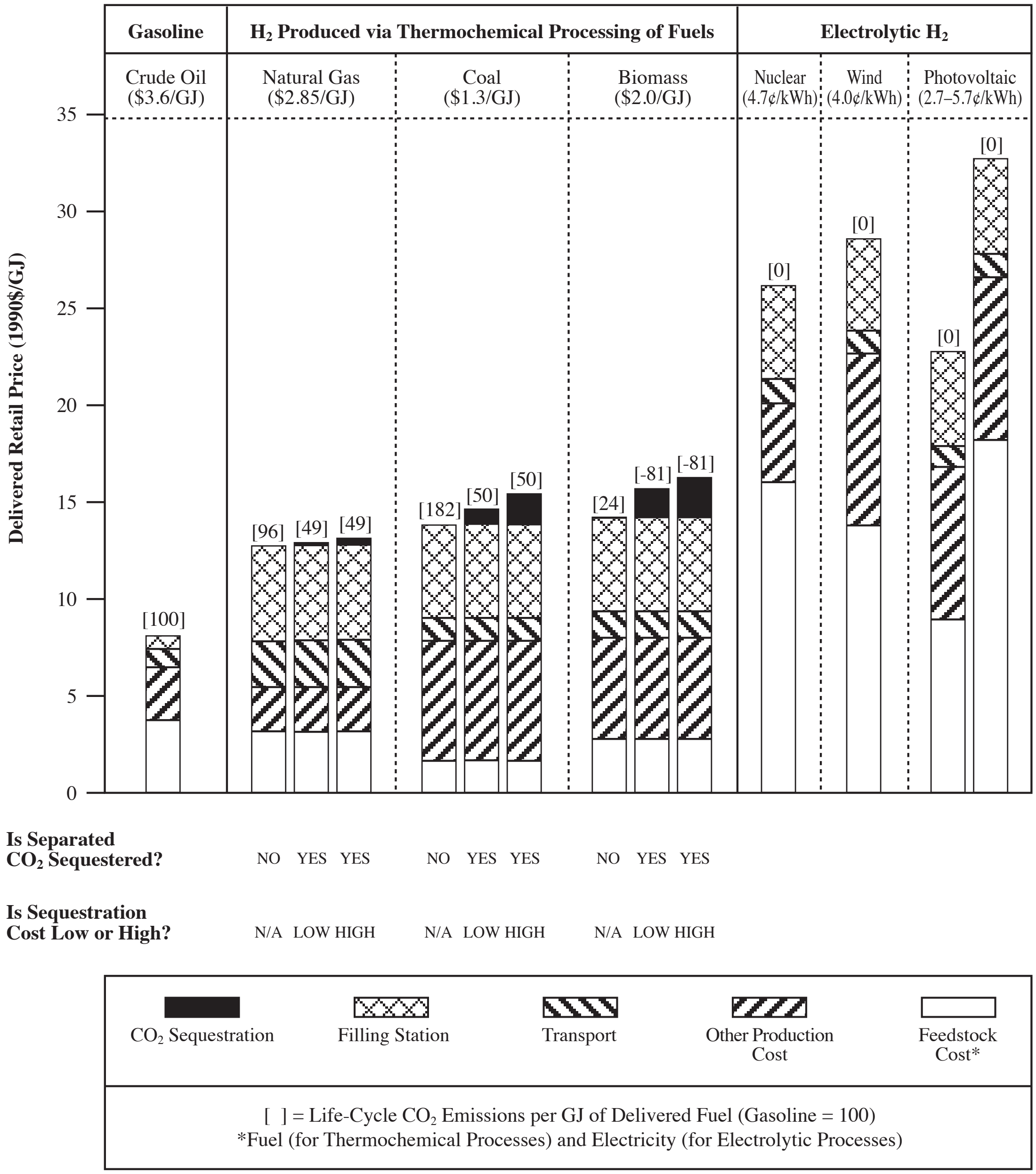


Figure 19-5: *Estimated Life-Cycle Costs to Consumers and CO_2 Emissions per GJ of Hydrogen (H_2) from Alternative Sources for Transport Applications, with a Comparison to Gasoline Derived from Crude Oil*—This figure and Figures 19-6 and 19-7 present alternative measures of cost and life-cycle CO_2 emissions characteristics for systems that provide H_2 derived from natural gas (via steam reforming), coal and biomass (via thermochemical gasification), and electrolytic sources, with comparisons to gasoline (Williams, 1996). Costs were calculated assuming a 10% discount rate, and fuel taxes were excluded. The assumed crude oil, natural gas, and coal prices are, respectively, the world oil price, the U.S. average wellhead price, and the average U.S. electric utility price projected for 2010 by U.S. DOE (EIA, 1995). The consumer gasoline price is for reformulated gasoline, which is estimated to be 16% higher than the price of ordinary gasoline derived from crude at the assumed price of $22/barrel. Plantation biomass prices that are comparable to or lower than the assumed price could be realized in large-scale applications in Brazil today and in the U.S. by 2020 if yield and cost goals for 2020 are realized as a result of successful R&D (see Section 19.2.5.2.1). The assumed electricity costs are for a 600 MW advanced passively safe nuclear plant having an installed cost of $1680/kW (EPRI, 1993); for post-2000 wind technology with an installed cost of $780/kW (Ogden and Nitsch, 1993); and for photovoltaic (pv) systems in areas with high insolation and installed costs of $550–1125 per kW—targets that plausibly could be met using advanced thin-film pv technologies in the long term (Ogden and Nitsch, 1993). Thermochemical production of H_2 generates a byproduct stream of pure CO_2, which can either be released to the atmosphere or compressed and piped to a site where it might be sequestered. The first bar for natural gas, coal, and biomass is the cost when this CO_2 is vented; the second and third bars are for when the separated CO_2 is sequestered, assuming low and high estimates of the sequestering cost (Hendriks, 1994). In the natural gas cases, it is assumed that the H_2 plant is located near a natural gas field and that the separated CO_2 is sequestered in depleted gas wells. For the coal and biomass cases, it is assumed that the separated CO_2 is sequestered in saline aquifers located 250 km from the plant. The numbers at the tops of the bars are the life-cycle CO_2 emissions in kg C per GJ of delivered fuel, relative to life-cycle emissions for gasoline.

compete in markets where energy-conversion equipment designed for hydrocarbon fuels is used. The situation would change markedly if conversion equipment designed to exploit the unique characteristics of hydrogen were used instead.

A class of technologies that could make a hydrogen economy feasible is represented by the fuel cell, which converts fuel directly into electricity without first burning it. The hydrogen fuel cell offers the potential for major contributions in transportation (Williams, 1993; Mark *et al*., 1994) and in distributed combined heat and power applications (A.D. Little, 1995; Dunnison and Wilson, 1994). The hydrogen fuel cell offers high thermodynamic performance, zero local air-pollution emissions, low maintenance requirements, and quiet operation. In mass production, automobiles powered by the proton exchange membrane (PEM) fuel cell would have much lower costs and much longer ranges between refuelings than battery-powered electric cars (Kircher *et al*., 1994; Ogden *et al*., 1994). Powered by either compressed hydrogen or methanol (a hydrogen carrier that would be "reformed" onboard the vehicle into a suitable hydrogen-rich gaseous fuel), PEM fuel-cell cars would require much less fuel and emit much less local pollution than hybrid internal-combustion engine/battery-powered cars, while offering comparable or greater range and comparable or lower life-cycle costs (Kircher *et al*., 1994; Biedermann *et al*., 1994).

Because of the much higher fuel economy, the cost of fuel per km of driving a fuel-cell car powered by thermochemically derived hydrogen is likely to be less than 65% of the cost for a gasoline-fired internal combustion engine car of comparable performance (see Figure 19-6)[6], and the total life-cycle cost of owning and operating a fuel-cell car is likely to be slightly less (see Figure 19-7), even though the cost of this hydrogen to the consumer, measured in $/GJ, would be up to about 75% more than for gasoline (see Figure 19-5).[7]

19.3. Low CO_2-Emitting Energy Supply Systems for the World

Each of the options discussed in Section 19.2 has the potential to reduce GHG emissions. To understand better their combined potential contributions to future energy supplies and emissions reductions, assessments are needed at the level of the global energy system. Such assessments should consider internal functional aspects of the energy system (such as the intermittency of solar and wind energy resources) and the linkages between the energy system and other areas for societal concern (such as land-use competition and security issues).

In order to start an assessment at the energy systems level, alternative versions of a Low-Emissions Supply System (LESS) were constructed. These LESS constructions illustrate the potential for reducing emissions by using energy more efficiently and by using various combinations of low CO_2-emitting energy supply technologies—including shifts to low-carbon fossil fuels, shifts to renewable or nuclear energy sources, and decarbonization of fuels, in alternative combinations. Energy supply systems were constructed for this exercise both from "the bottom up" (Section 19.3.1) and "the top down" (Section 19.3.2).

Emphasis in the LESS constructions is on the long term (2025–2100), the prospects for achieving deep reductions in CO_2 emissions from the energy sector with alternative supply mixes, and prospective costs. The need for a long-term focus is stressed in the Working Group I evaluations. Accordingly, emphasis was given to new or improved energy supply technologies that offer the potential for achieving deep reductions in emissions. By the year 2100, the global commercial energy system will have been replaced two to three times—providing many opportunities to change system performance through the use of various new technologies at the time of investment, both for capacity expansion and for replacement.

It is not realistic to probe the deep future taking into account only commercial technologies. The prospective performance and relative cost characteristics for the technologies selected for emphasis in the LESS constructions can be described with a reasonable degree of confidence with present knowledge; all are commercially available, commercially ready, or have good prospects for becoming commercial products within the next 1 or 2 decades, if adequate incentives are provided for the needed R&D and for launching the new industries involved.

To help clarify the options, alternative versions of the LESS were constructed with features that make each option markedly different from the others, and some important features distinguishing the alternatives are highlighted. In the bottom-up constructions, focused attention is given to five LESS variants. Four variants involve a high degree of emphasis on the efficient use of energy. Two of these—which were analyzed in the greatest detail, thus taken to be the reference cases—are a biomass-intensive (BI) variant and a nuclear-intensive (NI) variant. Also, a natural gas-intensive (NGI) variant and a coal-intensive (CI) variant were constructed to explore the extent to which deep reductions in emissions could be achieved using more fossil fuels. A fifth high-demand (HD) variant explores the implication of much greater energy demand growth.

A central finding of the LESS construction exercise is that deep reductions of CO_2 emissions from the energy sector are technically possible within 50 to 100 years, using alternative strategies. Many combinations of the options identified in this assessment could reduce global CO_2 emissions from fossil

[6] As shown in Figure 19-6, the fuel cost per km of thermochemical H_2 would increase only modestly, if the CO_2 separated at the H_2 production plant were isolated from the atmosphere and the extra cost of sequestering this CO_2 were charged to the consumer.

[7] Moreover, because the cost of fuel represents such a small fraction of the total cost of owning and operating a fuel-cell car, the total life-cycle cost for a fuel-cell car operated on electrolytic hydrogen would be less than 7% more than for a gasoline internal combustion engine car, even though the cost of electrolytic hydrogen per km for a PEM fuel-cell car would be up to 50% more costly (see Figure 19-7).

fuels from about 6 Gt C in 1990 to about 4 Gt C per year by 2050, and to about 2 Gt C per year by 2100. Because of the large number of combinations of options, there is flexibility as to how the energy supply system could evolve, and paths to energy system development could be influenced by considerations other than climate change, including political, environmental, and socioeconomic circumstances. However, higher energy demand levels reduce the flexibility for constructing

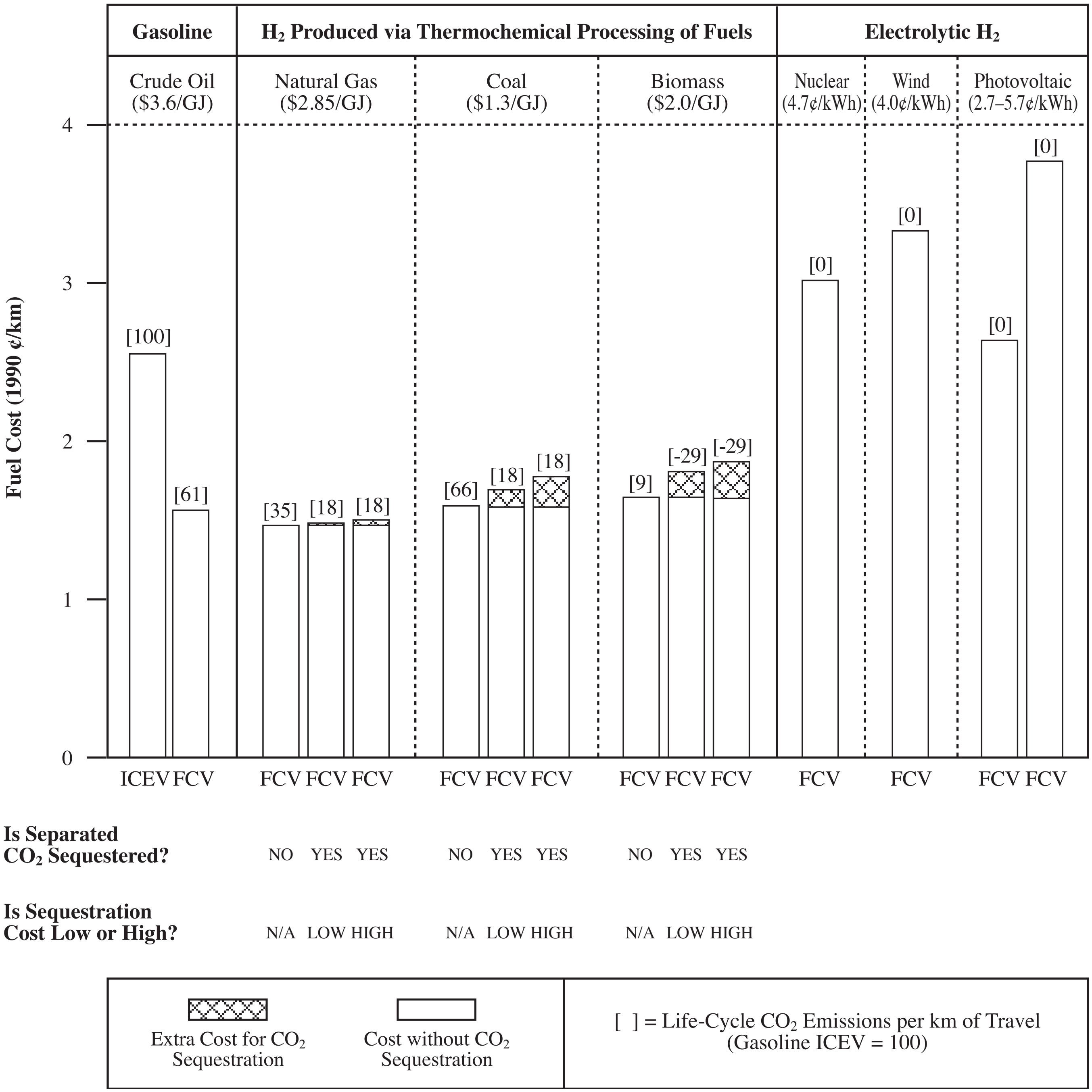


Figure 19-6: *Estimated Life-Cycle Fuel Costs to Consumers and CO_2 Emissions, per km of Driving Fuel Cell Vehicles (FCVs), for H_2 from Alternative Sources for Transport Applications, with a Comparison to Gasoline Derived from Crude Oil and Used in Internal Combustion Engine Vehicles (ICEVs) and FCVs*—The consumer prices and life-cycle CO_2 emissions for H_2 shown in Figure 19-5 are converted here to fuel costs and life-cycle CO_2 emissions per km of driving an FCV, along with a comparison of gasoline costs and lifecycle CO_2 emissions per km of driving, for both ICEV and FCV applications (Williams, 1996). Fuel taxes are not included. The reference gasoline ICEV is a year-2000 version of the Ford Taurus automobile with a fuel economy of 11.0 km/l. The H_2 FCV has performance characteristics that are comparable to those for this ICEV and a gasoline-equivalent fuel economy of 30.4 km/l. Fuel costs are also shown for an FCV operating on gasoline. In this case, the gasoline is converted via partial oxidation onboard the vehicle to a gaseous mixture of H_2 and CO_2, which is a suitable fuel gas for operating the fuel cell; the estimated fuel economy for the gasoline FCV is 18.0 km/l.

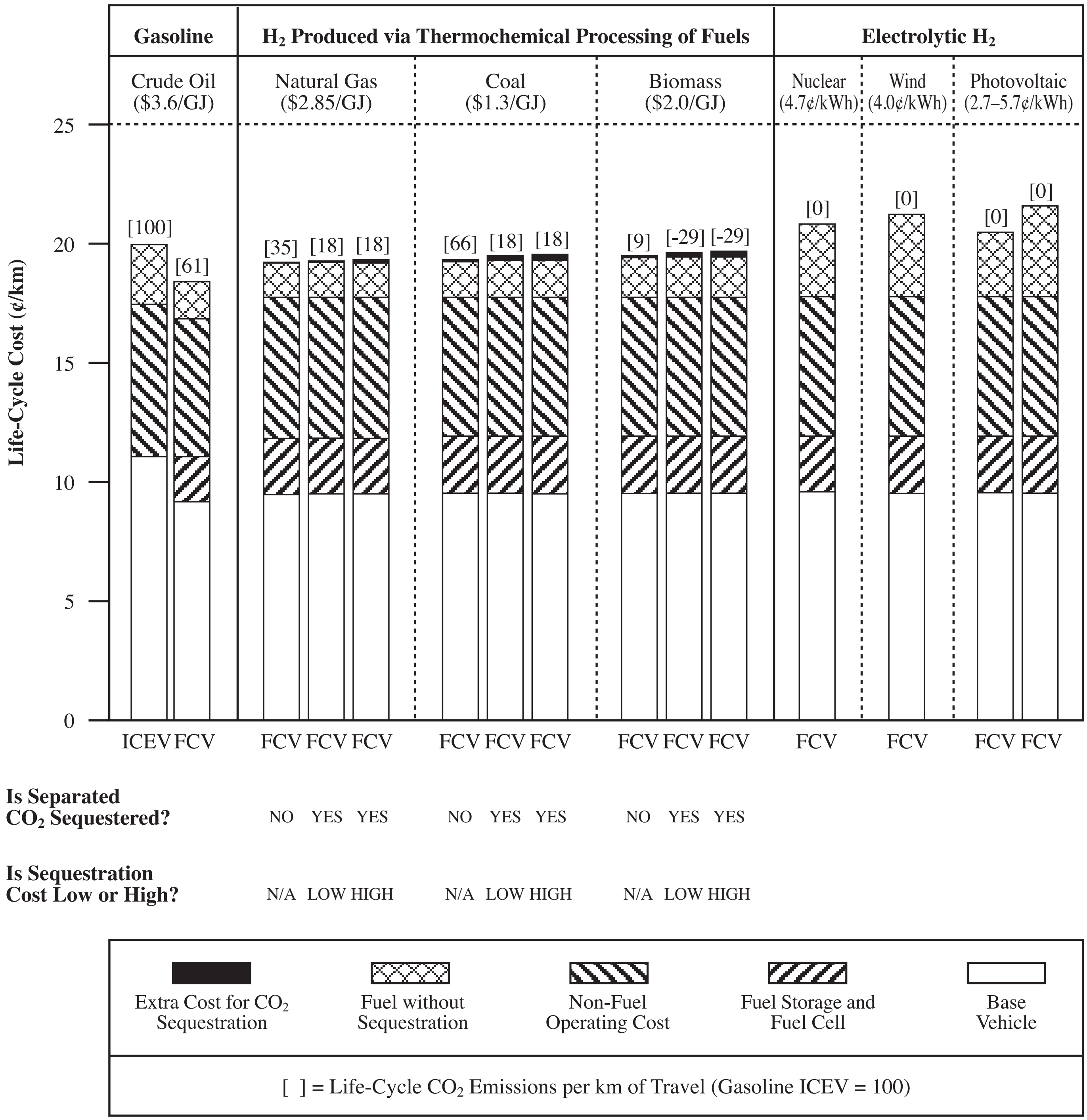


Figure 19-7: *Estimated Life-Cycle Costs to Consumers for Owning and Operating FCVs and CO_2 Emissions, per km of Driving an FCV, for H_2 from Alternative Sources for Transport Applications, with a Comparison to Gasoline Derived from Crude Oil and Used in ICEVs and FCVs*—Vehicle performance and cost characteristics are based on Ogden *et al*. (1994). The estimated fuel-economy characteristics of these vehicles are indicated in Figure 19-6. An operating lifetime of 11 years is assumed for both ICEVs and FCVs; however, FCVs are assumed to be driven 23,000 km per year, compared to 17,800 km per year for ICEVs; this reflects the lower operating costs expected for FCVs operated on thermochemically derived fuels. It is assumed that H_2 is stored onboard vehicles in carbon-fiber-wrapped aluminum tanks at high pressure (550 bar). Because of the bulkiness of gaseous H_2 storage, the H_2 FCV is designed for a range between refuelings of 400 km, compared to 640 km for a gasoline ICEV. The weight of the H_2 FCV is estimated to be 1.3 tons, compared to 1.4 tons for the ICEV. Initial costs are estimated to be $17,800 for an ICEV and $25,100 for an H_2 FCV (in mass production). The initial cost for a gasoline FCV is assumed to be $21,700—the same as the estimated cost for a methanol FCV (Ogden *et al*., 1994). Retail fuel taxes are included under “other non-fuel operating costs” at the average U.S. rate for gasoline used in ICEVs; to ensure that road tax revenues are the same for all options, it is assumed that retail taxes are 0.75¢ per km for all options (equivalent to 8.2¢ per liter or 31¢ per gallon for gasoline used in ICEVs).

supply-side combinations for deep reductions in emissions and increase overall energy system costs—underscoring the importance of higher energy efficiency.

Costs for energy services in each LESS variant relative to costs for conventional energy depend on relative future energy prices, which are uncertain within a wide range, and on the performance and cost characteristics assumed for alternative technologies. However, within the wide range of future energy prices, one or more of the variants would plausibily be capable of providing the demanded energy services at estimated costs that are approximately the same as estimated future costs for current conventional energy (see, for example, Figures 19-4, 19-6, and 19-7). It is not possible to identify a least-cost future energy system for the longer term, as the relative costs of options depend on resource constraints and technological opportunities that are imperfectly known, and on future actions to be taken by governments and the private sector.

The literature provides strong support for the feasibility of achieving the performance and cost characteristics assumed for energy technologies in the LESS constructions within the next 1 or 2 decades, though it is impossible to be certain until the research and development is complete and the technologies have been tested in the market. Moreover, these performance and cost characteristics cannot be achieved without a strong and sustained investment in R&D. Many of the technologies being developed would need initial support to enter the market, and to reach sufficient volume to lower costs to become competitive.

Market penetration and continued acceptability of different technologies ultimately depends on their relative cost,

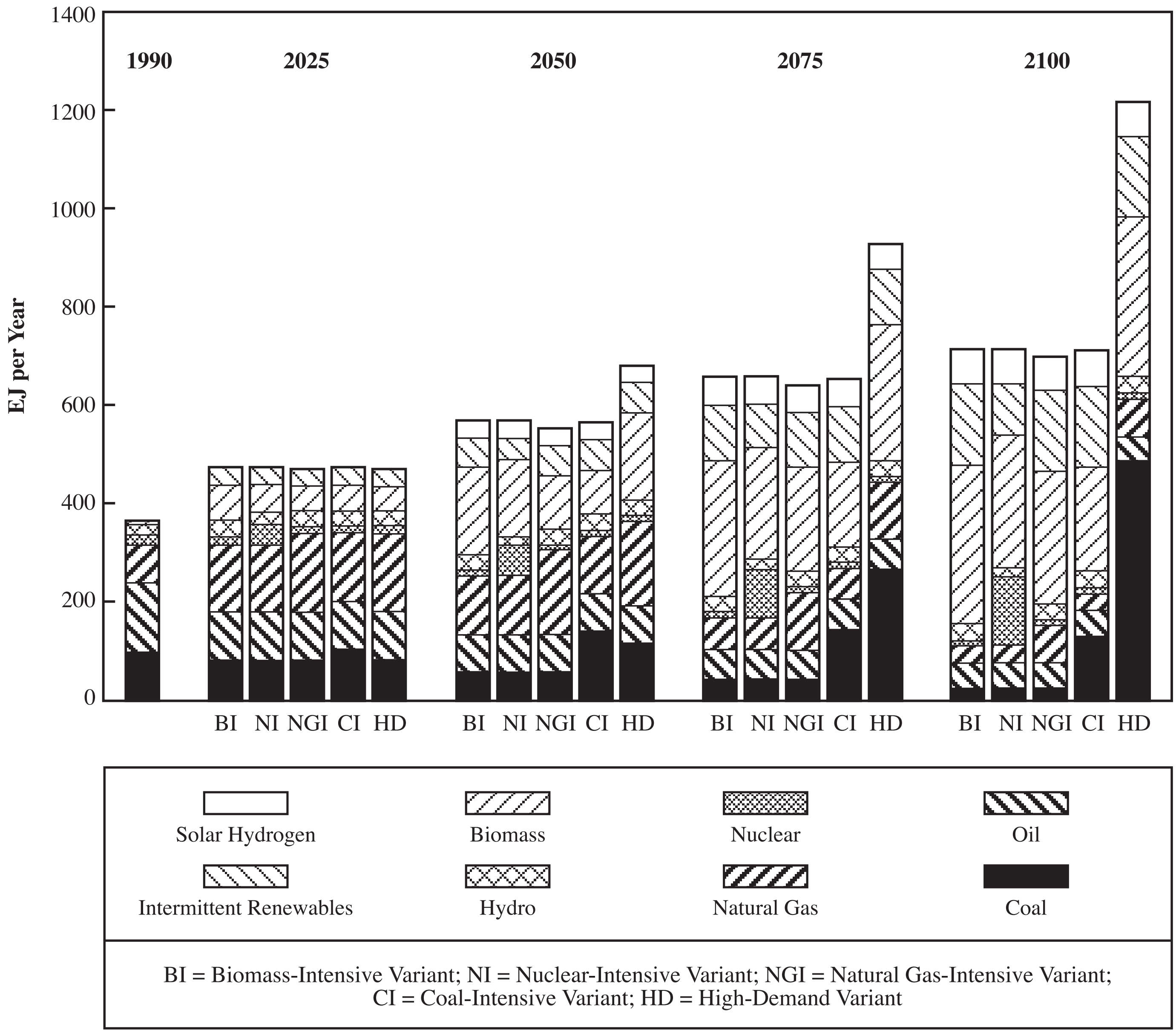


Figure 19-8: Global primary energy use for alternative LESS constructions.

performance (including environmental performance), institutional arrangements, and regulations and policies. Because costs vary by location and application, the wide variety of circumstances creates initial opportunities for new technologies to enter the market. Deeper understanding of the opportunities for emissions reductions would require more detailed analysis of options, taking into account local conditions.

The LESS alternatives are not forecasts; rather, they are self-consistent constructions indicative of what might be accomplished by pursuing particular technological strategies. These alternative paths to the energy future should be regarded as "thought experiments" exploring the possibilities of achieving deep reductions in emissions. Actual strategies for achieving deep reductions might combine elements from alternative LESS constructions. Moreover, there may well be other plausible technological paths that could lead to comparable reductions in emissions. More work is required to provide a comprehensive understanding of the prospects for and implications of alternative global energy supply systems that would lead to deep reductions in CO_2 emissions.

19.3.1. A Bottom-Up Construction for the LESS Reference Cases

The bottom-up LESS reference analysis involved constructing alternative sets of energy supplies for each of 11 regions of the world matched to energy demand levels adopted from a previous IPCC study. The study used a set of demand projections for electricity and for solid, liquid, and gaseous fuels used directly, by world region, for the years 2025, 2050, 2075, and 2100. These projections were developed by the Response Strategies Working Group (RSWG) of IPCC for its 1990 Assessment Report (RSWG, 1990). The RSWG prepared high and low economic growth variants of alternative energy scenarios, including Accelerated Policies (AP) scenarios characterized on the demand side by high rates of improvement in energy efficiency. The energy demand projections for the high

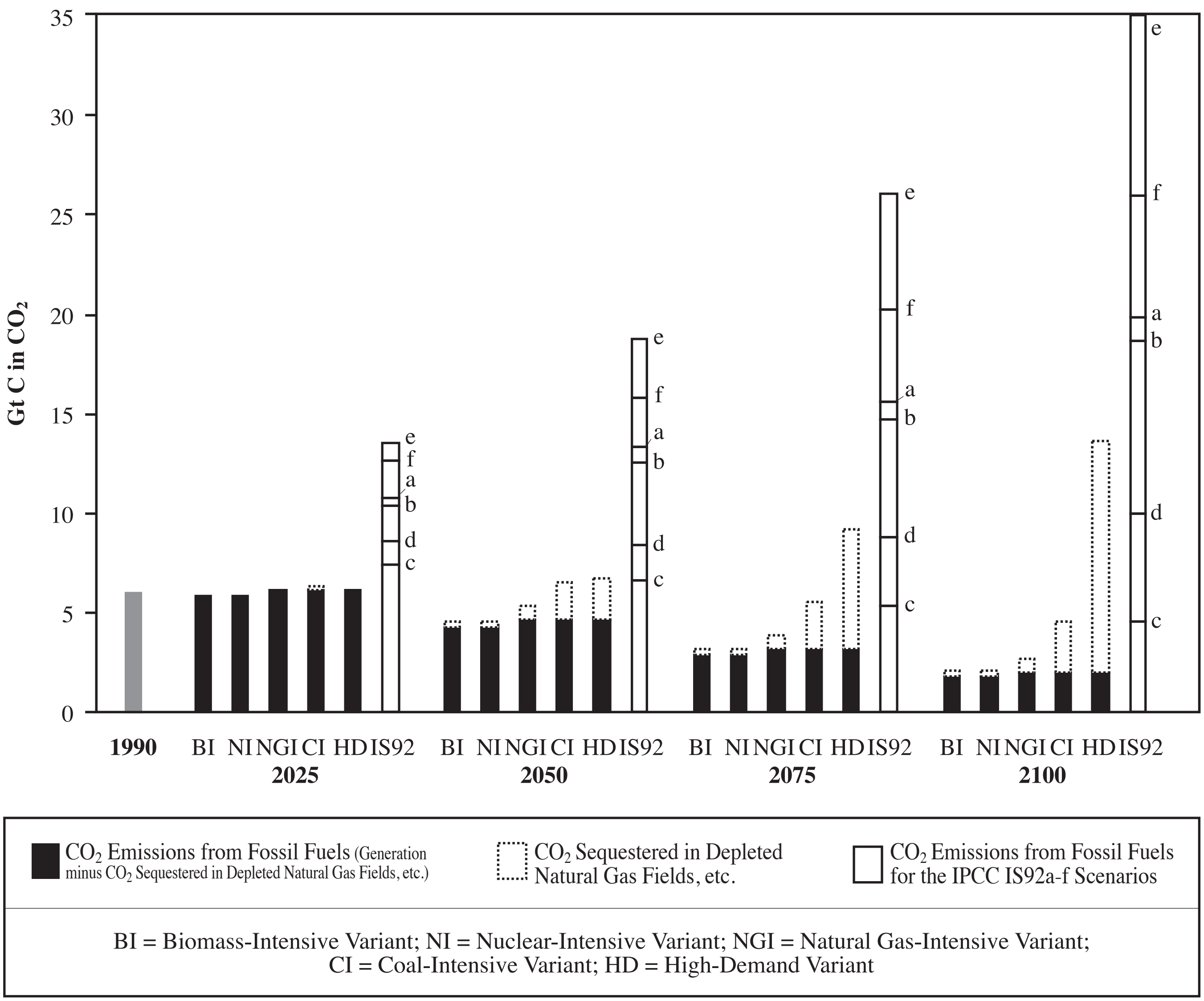
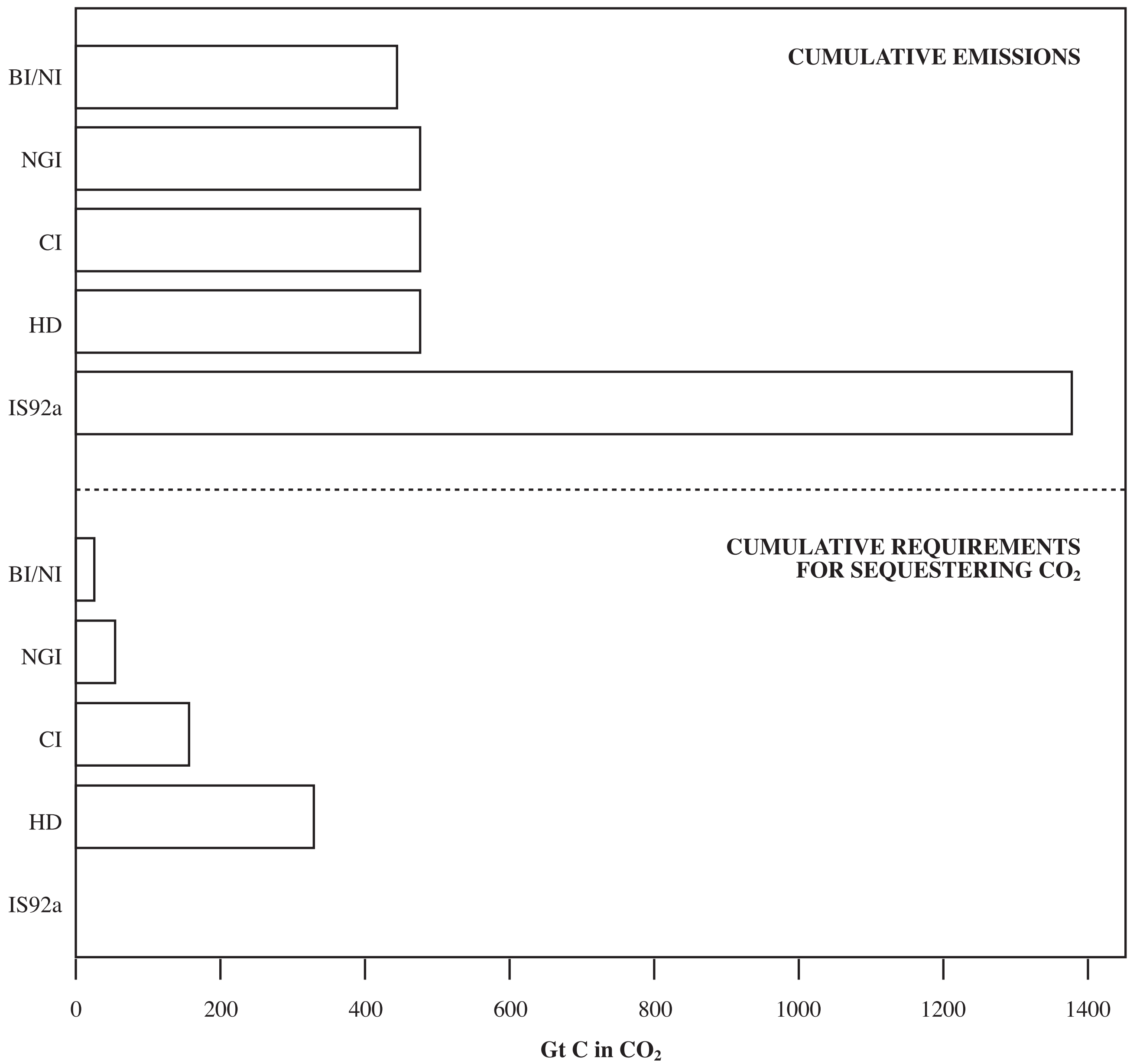


Figure 19-9: Annual CO_2 emissions from fossil fuels for alternative LESS constructions, with comparison to the IPCC IS92a-f scenarios.

economic growth variant of the AP scenarios were adopted for the reference cases of the LESS constructions. These projections are consistent with analysis in the energy demand sections of this report (Chapters 20–22). The demand profiles of the AP scenario were assumed as exogenous inputs to the supply analysis and were not critically reviewed here.

An AP scenario was chosen as the point of departure for the LESS constructions because typically there are large opportunities to reduce CO_2 emissions more cost-effectively via investments in more energy-efficient equipment than via investments in energy supply. The high economic growth variant was chosen to make clear that the potential for emissions reduction illustrated by the LESS constructions is the result of technological choice rather than reduced economic output. The LESS reference constructions are extensions and variants of a methodology developed in a previous study exploring the long-term prospects for renewable energy in the context of the same set of energy demand projections (Johansson *et al*., 1993a).

Given the AP energy demands for each region, energy supplies were constructed for the LESS variants that are consistent with each region's endowments of conventional and renewable energy sources and general expectations of relative prices.



BI = Biomass-Intensive Variant; NI = Nuclear-Intensive Variant; NGI = Natural Gas-Intensive Variant; CI = Coal-Intensive Variant; HD = High-Demand Variant

Figure 19-10: Cumulative CO_2 emissions from fossil fuel burning and CO_2 sequestration requirements, 1990–2100, for alternative LESS constructions, with a comparison to the IPCC IS92a scenario (IPCC, 1992).

Highlights of the LESS reference cases are presented in Box 19-2; salient global characteristics of these and other LESS variants are presented in Figures 19-8 to 19-12. Primary energy requirements for one of the reference cases, disaggregated into industrialized and developing regions, are presented in Figure 19-13. Details of the assumed demand projections and supply constructions are in Williams (1995a).

19.3.1.1. Fossil Fuels in the LESS Reference Cases

The roles for fossil fuels in the LESS constructions are estimated on the basis of private costs, without consideration of carbon taxes. Particular attention is given to resource constraints on oil and natural gas and local environmental restrictions on the use of coal.

For oil and natural gas, the key assumption is that they will be developed consistent with widely accepted estimates of ultimately recoverable quantities of conventional oil and gas. For undiscovered resources, the mean estimates of the U.S. Geological Survey (Masters *et al*., 1994) are assumed for regions outside the United States, and U.S. Department of Energy estimates (Energy Information Administration, 1990) are assumed for the United States. Unconventional oil and gas resources are not taken into account. It is assumed that all reserves and estimated recoverable, undiscovered conventional oil and gas resources (some 11,300 EJ of oil and 12,500 EJ of natural gas as of 1993—equivalent to 80 and 160 years of supply at 1990 production rates) will eventually be used for energy.

From a GHG perspective, it matters little how oil and gas consumption evolves over time within this general framework. From an energy policy perspective, it makes sense to shift the mix more to gas in light of comparable amounts of estimated ultimately recoverable conventional resources and a present oil consumption rate that is nearly twice that for gas. To increase the transparency of the analysis, two simplifying assumptions

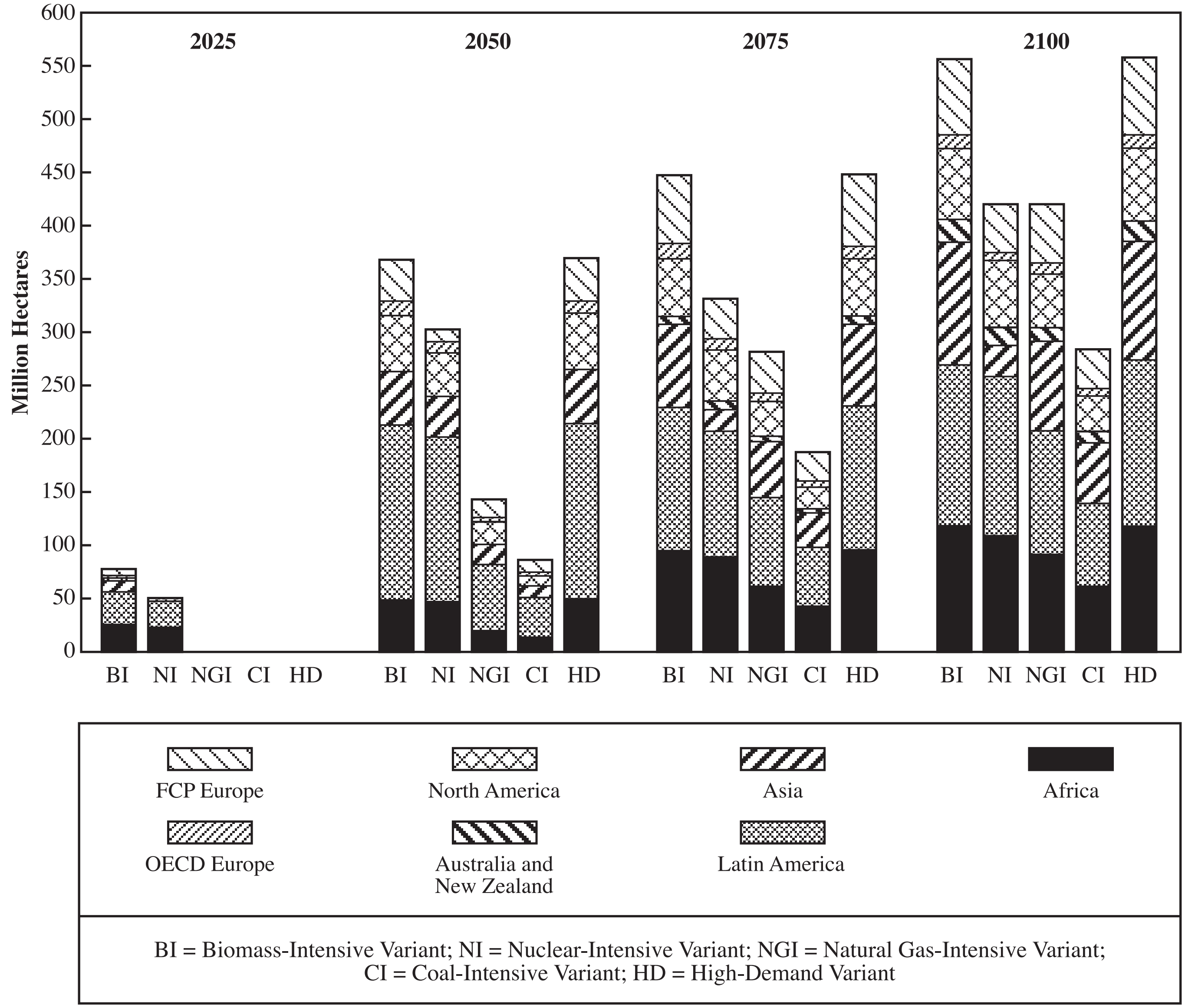


Figure 19-11: Land areas of biomass energy plantations by region for alternative LESS constructions.

were made: For each region, oil production declines at a constant exponential rate such that 80% of the estimated remaining ultimately recoverable resources is used up by 2100; and 80% of the ultimately recoverable natural gas resources also is used up for each region by 2100, but natural gas use first increases to the year 2025 (at the same rates as in the IPCC IS92a scenario) and thereafter declines at a constant exponential rate.

The LESS constructions assume that hydrogen becomes an important energy carrier (for example, for use in fuel-cell vehicles). Hydrogen derived from natural gas often will be one of the least-costly supplies of hydrogen (see Figure 19-5), and sequestration in depleted natural gas fields of CO_2 recovered at hydrogen production plants (containing two-thirds of the carbon in the original natural gas) is used as a decarbonizing strategy (see Figure 19-5). Thus, it is assumed that some natural gas (0% by 2025, 25% by 2050, 50% by 2075, and 75% by 2100) is reformed near the wellhead to hydrogen and that the stream of pure CO_2 generated in conversion is sequestered in depleted natural gas fields, increasing the cost of hydrogen to consumers by 1–3% (see Figure 19-5).

Under these conditions, cumulative CO_2 emissions from 1990 to 2100 from the use of oil and natural gas would be 275 Gt C. If there were no other fossil fuels, it might be feasible to stabilize the atmospheric concentration of CO_2 at or near the present level. IPCC Working Group I has estimated that cumulative CO_2 emissions of 300–430 Gt C in the 21st century would be consistent with stabilization of the atmospheric CO_2 level at a concentration of 350 ppm (IPCC, 1994).

Remaining coal resources are huge, however. Without decarbonization, burning all of the estimated ultimately recoverable coal resources (see Table B-3 in Chapter B) would lead to the

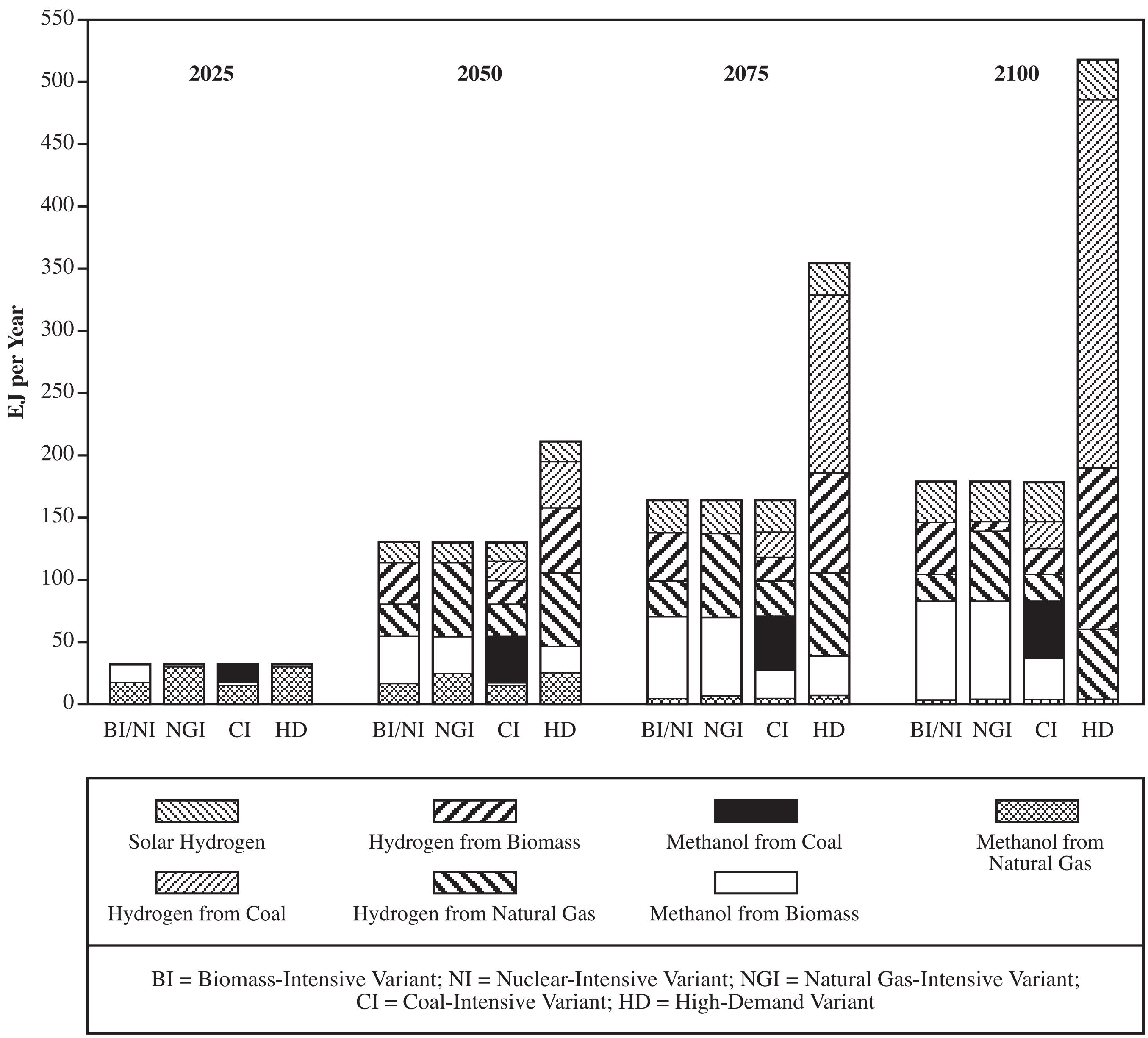


Figure 19-12: Methanol and hydrogen production from alternative sources for alternative LESS constructions.

cumulative release of 3,100 Gt C. Moreover, even if the rate of coal use remained constant at the 1990 level, the burning of coal without decarbonization would add about 270 Gt C to the atmosphere between 1990 and 2100.

The LESS constructions present alternative strategies for reducing emissions from burning coal. In the reference cases, a strategy for reducing coal use is articulated. In the coal-intensive (CI) and high-demand (HD) variants presented later, emissions are reduced instead by pursuing coal decarbonization strategies.

Although coal is abundant and cheap, it is also a dirtier, more difficult-to-use fuel than oil or natural gas. Where there are strict rules to ensure that coal is used in clean ways, coal will face stiff economic competition from many alternative energy sources, both for power generation (see Section 19.3.1.2) and for the production of synthetic fuels that are used directly (see Section 19.3.1.3). Key assumptions underlying the LESS reference cases are that by the time frame of interest (2025–2100), all regions of the world will have adopted environmental standards for using coal equivalent to the most stringent standards now in place in the industrialized world; and, if a nonfossil fuel alternative to coal is available at approximately the same cost for the final product (electricity or synthetic fuel) with these environmental standards under the assumptions about future technology, the alternative is selected. Under these conditions, coal can be plausibly greatly reduced in the LESS reference cases, although in developing countries coal use increases

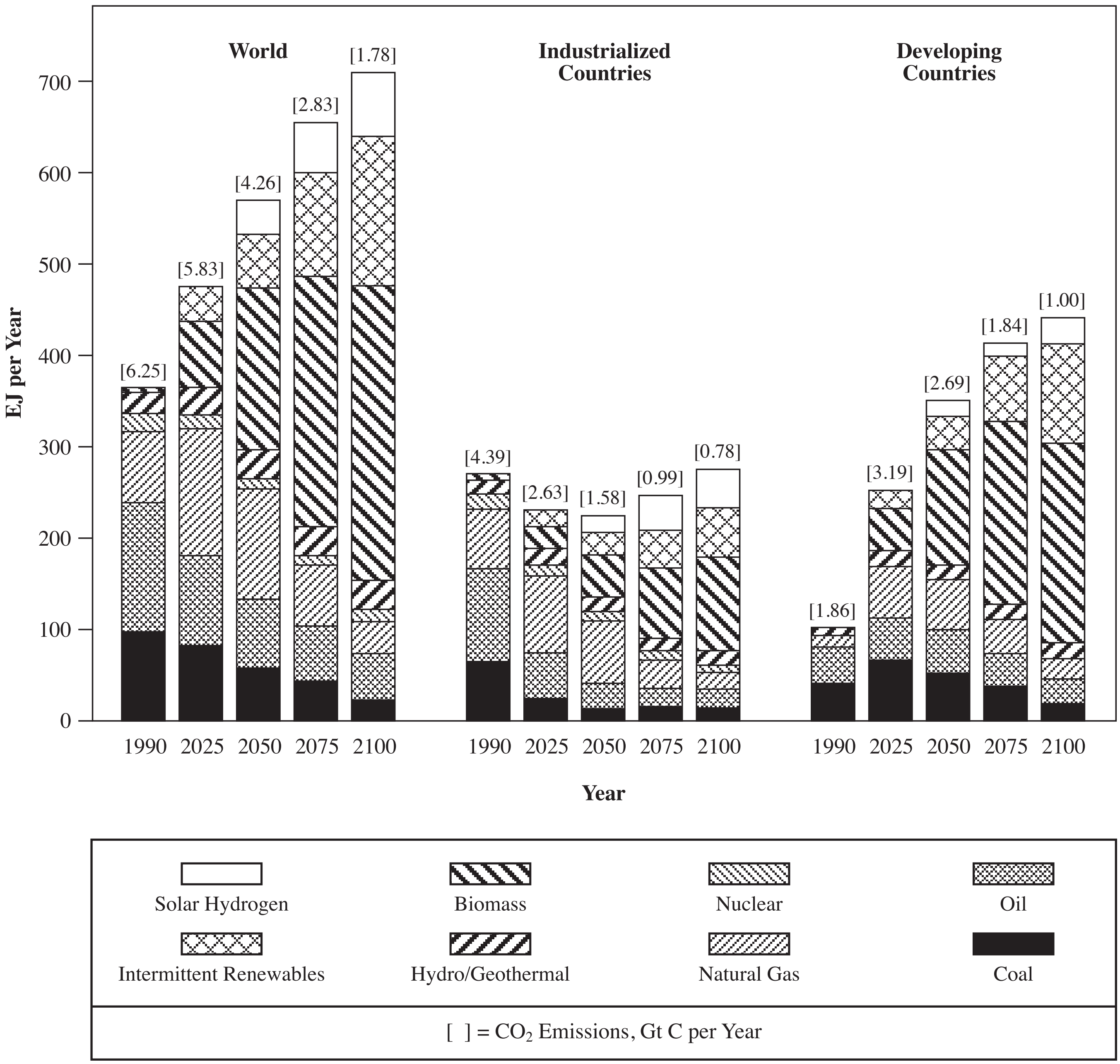


Figure 19-13: Primary commercial energy use by source for the biomass-intensive variant of the LESS constructions, for the world and for industrialized and developing countries.

Box 19-2. Highlights of the LESS Reference Cases (BI and NI Variants)

World population grows from 5.3 billion in 1990 to 9.5 billion by 2050 and 10.5 billion by 2100. Gross domestic product (GDP) grows 6.9-fold by 2050 (5.3-fold and 13.6-fold in industrialized and developing countries, respectively) and 24.6-fold by 2100 (12.8-fold and 68.3-fold in industrialized and developing countries, respectively), relative to 1990. Because of emphasis on energy efficiency, primary energy consumption rises much more slowly than GDP. Global primary commercial energy use roughly doubles, with no net change for industrialized countries but a 4.4-fold increase for developing countries, 1990–2100 (Figure 19-13).

Oil production declines in all regions, at a global average rate of 1.0% per year until 2100, when oil production is produced at 35% of the 1990 rate. Global natural gas production rises 84% by 2025, before beginning a decline at an average rate of 1.8% per year, 2025–2100; by 2100, natural gas is produced at 48% of the 1990 rate. Global coal production declines continually, but in developing countries it first rises 70% by 2025 before beginning to decline (see Figure 19-13). Whereas the decline in oil and gas production is determined by resource constraints, declining coal production is due to competition from nonfossil energy.

Total fossil fuel use stays roughly constant, 1990–2025, but its share in global energy declines from 86% to 67% in this period and to 15% by 2100, as a result of a shift to renewables in the BI variant and to nuclear plus renewables in the NI variant (see Figure 19-8). The NI variant involves increasing nuclear capacity worldwide 10-fold by 2100, so that nuclear accounts for 46% of total electricity in 2100, while hydro, biomass, and intermittent renewables (wind, photovoltaic, and solar thermal-electric power) account for 6%, 10%, and 34%, respectively. In the BI variant, nuclear provides 3% of electricity in 2100; hydro, biomass, and intermittent renewables contribute 10%, 29% and 54%, respectively.

Biomass plays a major role (especially as a feedstock for MeOH and H_2 production and power generation), accounting for 72 EJ or 15% of primary energy in 2025 (47% of biomass is for power generation) and rising to 325 EJ or 46% of primary energy by 2100 (29% for power generation) in the BI variant. In the NI variant, the contribution from biomass is 12% in 2025 (of which 35% is for power generation) and 38% in 2100 (of which 14% is for power generation).

MeOH and H_2 play growing roles as energy carriers in both the BI and NI variants (see Figure 19-12). Their production accounts for 10% of primary energy in 2025, rising to 40% by 2100 (about the same as for electric power generation by then). Natural gas provides nearly 60% of the energy from these energy carriers in 2025, but its share declines to 14% by 2100, while the biomass share increases from about 40% in 2025 to 67% by 2100. Electrolytic H_2 makes no contribution in 2025 but provides 12.5% of the energy from these energy carriers in 2050 and 20% in 2100.

Oil exports from the Middle East decline absolutely but grow as a percentage of global oil consumption—from about 20% in 1990 to more than 25% in 2025 and 33% in 2100. Total energy exports from the Middle East double, 1990–2050, before declining back to the 1990 level by the year 2100 (see Figure 19-14) as a result of growth in exports of natural gas and H_2 derived from both natural gas and solar electricity via electrolysis, which offset the decline in oil exports. Since H_2 is far more valuable than natural gas and oil, the monetary value of Middle East exports increases continually throughout the next century.

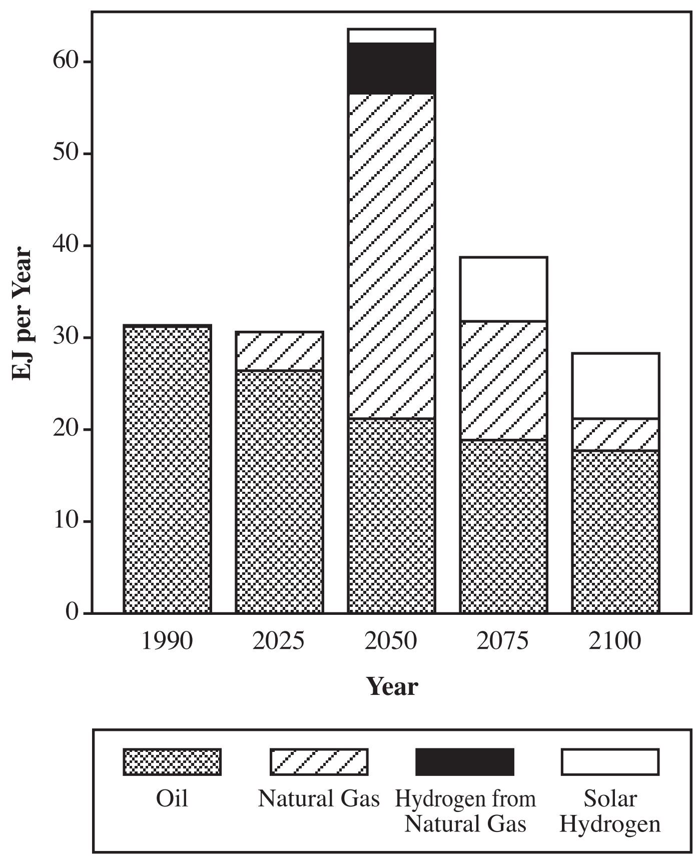


Figure 19-14: Net exports of fuels from the Middle East in the biomass-, nuclear-, and coal-intensive variants of the LESS constructions.

through 2025 before declining (see Figure 19-13 and Box 19-2). If nations elect not to control SO_x or other local pollutant emissions to these levels, prices for coal-derived energy would be lower, and alternatives to coal less attractive in economic terms.

Under these conditions, global CO_2 emissions decline from 6.2 Gt C in 1990 to 5.9 Gt C in 2025 and to 1.8 Gt C in 2100 for both of the LESS reference cases. Cumulative emissions from 1990 to 2100 amount to 448 Gt C, of which 182 Gt C comes from oil, 93 Gt C is from natural gas, and 172 Gt C is from coal.

19.3.1.2. The Electricity Sector in the LESS Reference Cases

Under the demand assumptions of the AP scenario, there is a continuing shift to electricity in the LESS reference cases, with total generation increasing 2.9- and 4.2-fold by 2050 and 2100, respectively. Total primary energy use increases only 1.6- and 1.9-fold, respectively. In the reference cases, the possibilities for achieving deep reductions in emissions both without (BI variant) and with (NI variant) a major expansion of nuclear power are explored.

19.3.1.2.1. The biomass-intensive variant for the electric sector

The BI variant explores the potential for using renewable electric sources in power generation by combining the results of modeling exercises, such as those described in Section 19.2.6.2 using the SUTIL model with considerations of regionally varying resource endowments and constraints. Under these conditions, estimates were made of potential contributions to electric grids from renewables—both intermittent renewables (wind, photovoltaic, and solar thermal-electric technologies) and advanced biomass electric-generating technologies (biomass-integrated gasifier/gas turbine technologies through 2025 and biomass-integrated gasifier/fuel-cell technologies for 2050 and beyond). Advanced gas turbine and fuel-cell technologies fueled with natural gas-derived hydrogen also are stressed. The level of nuclear generation remains constant from 1990 to 2100.

At the global level, 30% of electricity is supplied by intermittent renewables by 2050 in the BI variant, with substantial regional variations (for example, 10% in Africa; 18% in OECD Europe). This appears to be achievable without the use of new storage technologies if these systems are backed up by thermal power systems having characteristics similar to those of natural gas-fired combined cycles and peaking turbines (see, for example, Figure 19-4). Storage technologies make it possible to increase the global average contribution to more than 50% by 2100.

Natural gas is emphasized in the BI variant because of its favorable economics and relatively low CO_2 emissions in combined-cycle and fuel-cell configurations. Also, because natural gas-fired gas turbines and combined cycles have low unit capital costs and can change output levels quickly, they are good complements to intermittent renewable technologies. The share of natural gas in electricity generation increases from 16% in 1990 to 25% by 2050 but falls thereafter to 5% by 2100.

Biomass can provide baseload renewable electricity without ancillary storage. Its contribution to global electricity supply in the BI variant averages one-sixth of the total from 2025 to 2050, increasing to one-quarter from 2075 to 2100. Initial biomass applications involve mainly biomass residues in industrial cogeneration applications, but over time plantation biomass plays an increasing role.

At the global level, coal-based power generation declines nearly 50% by 2050 and 100% by 2100, but it increases 2.7-fold in centrally planned Asia plus South and East Asia from 1990 to 2050 before declining. It is assumed that the rapidly expanding market for coal power there provides a favorable environment for innovation—so energy-efficient, coal-integrated gasifier/gas turbine power cycles become the norm by 2025, and coal-integrated gasifier/fuel-cell technologies become the norm by 2050.

For the power sector as a whole, emissions decline from 1.7 Gt C/yr in 1990 to 1.0 Gt C/yr by 2050 and to 0.06 Gt C/yr by 2100.

The central result of this analysis—that deep reductions in emissions from the power sector are achievable with the BI variant—would not be qualitatively changed by making a significant change in an individual component of the power supply. Consider, for example, the hydropower contribution. By 2050, hydropower generation increases 2.2-fold relative to 1990 and then remains constant. Although this is only 50–80% of the estimated economically exploitable potential (Moreira and Poole, 1993), large hydropower projects are increasingly being challenged on social and environmental grounds. Cutting the hydro increment by half between 1990 and 2050 might be compensated by a 14% increase in the contribution from intermittent renewables by 2050 without fundamentally changing the basic structure of the BI variant and with no increase in global emissions. If the cut in the increment were compensated instead by natural gas power generation, global gas supply requirements in 2050 would go up only 7%, and global emissions would increase only 0.12 Gt C/yr (if the gas were not decarbonized) or 0.03 Gt C/yr (if it were).

Key to the economics of the BI variant are assumptions about relative fuel prices. The results of the SUTIL modeling exercise shown in Figure 19-4 are for electric utility fossil fuel prices projected by the U.S. Department of Energy (U.S. DOE) for the United States in the period near 2010 (Kelly and Weinberg, 1993). Since that modeling exercise was carried out, the coal price projected by U.S. DOE for U.S. electric utilities in 2010 has fallen from \$2.0/GJ to \$1.3/GJ. This reduction in coal price implies a 15% reduction in the busbar cost for the advanced coal power-generation technology to which the advanced biomass power-generation technology was compared in Figure 19-4. Such a sharp drop in coal prices makes it much more difficult for biomass to compete. However, more detailed estimates of future plantation biomass costs have been made since the modeling exercise illustrated in Figure 19-4 was carried out (Graham *et al*., 1995; Turnure *et al*., 1995), indicating that biomass prices of \$1.5–1.8/GJ could be expected in the U.S. for plantation production levels up to 5 EJ/yr by 2020 (see Section 19.2.5.2.1). This implies that the electric generation cost reduction for biomass would be about the same as for coal, relative to what was modeled in Figure 19-4 (see footnote 5). But if coal prices turn out to be lower still, as projected in some private forecasts (DRI/McGraw-Hill, 1995), and if biomass conversion technologies turn out to be less efficient and more capital-intensive than coal conversion technologies [e.g., if the more pessimistic assumptions of Turnure *et al*. (1995) relating to biomass turn out to be true], then biomass would require a significant subsidy to compete (see Section 19.2.5.2.2).

The fossil fuel prices for electric utility users assumed in Figure 19-4 are consistent with long-term prices generated independently by the "top-down" global model described in Section 19.3.2. However, other "top-down" models produce different results. In a recent modeling exercise carried out by the Energy Modeling Forum (Gaskins and Weyant, forthcoming), five different models estimated five different average electric-utility coal prices for 2020; these estimates ranged from \$1.1 to \$2.3/GJ and averaged \$1.6/GJ.

The largest uncertainty regarding the prospects for an economically competitive, renewables-intensive electric future probably is the trend in relative fuel prices. However, the BI variant could plausibly provide demanded energy services at costs that are approximately the same as estimated future costs for current conventional technology, unless the lowest estimates for fossil fuels are realized and the costs projected for renewables turn out to be much too low.

19.3.1.2.2. The nuclear-intensive variant for the electric sector

The nuclear-intensive (NI) variant of the reference case involves a revitalization of the nuclear option and extensive deployment of nuclear electric power technology worldwide. Because the power sector is largely decarbonized in the next century under the BI variant (with CO_2 emissions amounting to only 0.06 Gt C/yr in 2100), it is assumed that the energy contributions from fossil fuels are identical for the NI and BI variants. Thus, the NI variant represents an alternative way to achieve the LESS reference case level of CO_2 emissions reduction from the power sector. It involves a major expansion of nuclear power along with a lesser (but still substantial) contribution from renewable electric sources than with the BI variant. The projections for nuclear electric capacity and generation worldwide in the long term would be technically feasible but would require the removal of policy barriers such as moratoria on construction, political decisions to abandon nuclear power, and the absence of support from development banks for nuclear power projects.

The main technical constraints on the growth of nuclear capacity are construction lead times and industrial capabilities for building power plants and fuel-cycle facilities. The availability of sites for nuclear installations—including radioactive waste repositories—was checked by region, taking into account the risk of earthquakes, the need for cooling, and population density.

The nuclear electricity generation projections were derived from penetration curves in each region, based upon the present status and trends of national nuclear programs. The asymptotic share of nuclear power in electricity generation was estimated by region, taking into account the availability of alternative energy sources and the size of the grid-connected electricity network (Semenov *et al*., 1995).

Under this set of assumptions and constraints, the installed nuclear capacity would grow from the present 330 GW_e to about 3,300 GW_e in 2100 (see Table 19-8). Nuclear power

Table 19-8: *Nuclear power in the nuclear-intensive (NI) variant of the LESS base case.*

	2025			2050			2075			2100		
Region	Nuclear Elect. Gen. (TWh/yr)	Nuclear Share of Total Elect. (%)	Nuclear Capacity (GW_e)	Nuclear Elect. Gen. (TWh/yr)	Nuclear Share of Total Elect. (%)	Nuclear Capacity (GW_e)	Nuclear Elect. Gen. (TWh/yr)	Nuclear Share of Total Elect. (%)	Nuclear Capacity (GW_e)	Nuclear Elect. Gen. (TWh/yr)	Nuclear Share of Total Elect. (%)	Nuclear Capacity (GW_e)
Africa	56	5	8	208	10	31	434	15	66	678	20	103
Asia	1583	21	240	3672	27	556	6479	36	982	9510	45	1442
Australasia and New Zealand	7	5	1	17	10	3	25	15	4	37	20	6
Eastern and Central Europe	1184	30	179	2187	40	331	3349	50	507	4527	60	686
Latin America	204	10	31	849	20	98	1289	30	195	2000	40	303
Middle East	89	10	15	212	12	32	342	15	52	471	17	71
North America	1053	30	159	1525	39	231	2008	48	304	2566	57	389
Western Europe	634	30	96	1090	45	165	1598	60	242	2159	75	327
Total	**4764**	**23**	**721**	**9352**	**30**	**1447**	**15524**	**38**	**2352**	**21948**	**46**	**3327**

would be a major contributor to electricity generation in North and Latin America, Asia, and Europe, with a share ranging from 40–75% by 2100; in Africa, Australia, New Zealand, and the Middle East, the share is less than 20%. Worldwide, nuclear power would provide 46% of electricity by 2100, compared with 17% at present; nuclear's share of electricity would be half as large as that for renewables by 2025, rising to a comparable share by 2100.

With breeder reactors, the availability of natural resources would not place any major constraint on the development of nuclear electricity generation (see Section 19.2.4). It is assumed for the NI variant that the first breeder reactors are commercially deployed in 2025. This would make it possible to support projected nuclear electricity generation over the next century with currently known uranium resources.

At the back end of the fuel cycle, the management of spent fuel would require interim storage capacities and the implementation of final disposal repositories for radioactive waste. Nuclear power plants currently generate about 5 tons of spent fuel per TWh of electricity. With the development of advanced reactors, this quantity will decrease. The NI variant would lead to some 6.3 million tons of accumulated spent fuel by 2100 with current technologies. Efficiency improvements in nuclear fuel utilization—for example, higher burn-up—and deployment of advanced fission reactors are likely to reduce the amount of spent fuel. Because the deployment of breeder reactors is assumed for the NI variant, most spent fuel would be reprocessed, and the volume of high-level waste created would be on the order of 1 $m^3/GW_e/yr$. The accumulated volumes to be disposed of would be some 200,000 m^3 by 2100.

Because the deployment of breeder reactors is assumed for the NI variant, a significant amount of spent fuel would be reprocessed and the fissile materials recycled in reactors. In the long term, the deployment of breeders would reduce plutonium inventories to materials contained in fuel-cycle facilities—that is, reprocessing and mixed-oxide (MOX) fuel fabrication plants or in reactors. The plutonium generation rate in 2100 would be in the range of 0.1–3 million kg/yr, depending on the mix of nuclear technologies. The plutonium inventory would be on the order of 50–100 million kg and would require technical and institutional safeguards to prevent diversions to nuclear weapons purposes (see Section 19.2.4).

The challenges of managing material usable for weapons would be considerably less daunting if the deployment of plutonium breeder reactors could be avoided. This might be possible if uranium could one day be economically recoverable from seawater, if denatured thorium-based fuel cycles could be successfully developed, or if much of the nuclear expansion after 2050 were based on fusion instead of fission. Fusion plants would be less likely to contribute to the acquisition of nuclear-weapons capabilities by subnational groups and would be easier to safeguard against clandestine use for fissile material production by governments (Holdren, 1991).

Nuclear power could be expanded more than is projected for the NI variant if potential nonelectric markets also were taken into account—notably if nuclear energy were used for industrial process heat, for DH, for potable water production, and for electrolytic hydrogen production (see, for example, Figure 19-4).

19.3.1.3. Fuels Used Directly in the LESS Reference Cases

Activities that involve the direct use of fuels account for nearly three-quarters of CO_2 emissions at present. Although the direct use of fuels is projected to grow much more slowly than electricity use, the present high level of emissions and expected rapid growth in transport make the realization of deep reductions in this area a daunting challenge.

The challenge of reducing emissions for fuels used directly is met in the LESS reference cases by shifting to natural gas (with some decarbonization—see Section 19.3.1.1) and biomass and to synthetic fuels derived from them. The options stressed include solid biomass fuel for industry, biogas from dung, and especially methanol and hydrogen derived from natural gas and biomass that would be used mainly in fuel cells.

It is assumed for all the LESS constructions that low-temperature fuel cells come into wide use for transportation and other applications before the end of the first quarter of the next century. Although hydrogen is the preferred fuel for fuel-cell vehicles, it is assumed for the LESS constructions that in the early decades of the next century, the dominant fuel would be methanol (see Figure 19-12), an easy-to-use liquid fuel that poses fewer challenges to the infrastructure than hydrogen. For applications to fuel-cell vehicles, the costs per kilometer of driving to the consumer for methanol derived from natural gas and biomass would be comparable to the costs for hydrogen derived from these fuels (Williams *et al*., 1995a, 1995b)—and thus to the cost of gasoline derived from crude oil in this period (see, for example, Figure 19-6).

In the first two decades of the next century, natural gas prices are likely to be relatively low. Thus, it is assumed that about 60% of the methanol is derived from natural gas in 2025 (see Figure 19-12). After 2025, it is expected that natural gas prices would rise and natural gas supplies would decline in the BI variant. Thus, there would be a shift in the mix of primary feedstocks from natural gas to biomass and at the same time a shift in the methanol/hydrogen mix toward greater use of hydrogen. The share of hydrogen would grow from 0% in 2025 to more than 50% in 2100 (see Figure 19-12).

Because of the assumption that biomass could be widely competitive in applications where biofuels are used directly, the demand for biomass energy is high in the BI variant. Because nuclear power provides only electric power in the NI variant, the contributions from biomass (see Figure 19-8) and from biomass plantations (see Figure 19-11) are almost as large for this variant as for the BI variant.

Until 2025, most biomass supplies would be residues of the forest-product and agricultural industries and urban refuse. Later, however, the dominant source would be biomass energy farms or plantations. The land area committed to plantations in the BI variant is 83 Mha in 2025 and increases to 572 Mha by 2100. The corresponding land areas for the NI variant are 55 and 433 Mha, respectively. The distribution of land use in plantations by region is indicated in Figure 19-11.

In the LESS reference cases, methanol would become a major commodity traded in international energy markets. Thus, by the middle of the next century, regions such as Latin America and sub-Saharan Africa—where there are large areas potentially available for growing biomass—would become major exporters of biomass-derived methanol.

There are no contributions from electrolytic hydrogen in the LESS reference cases in 2025. Costs for hydrogen derived electrolytically from photovoltaic, wind, or nuclear sources are likely to be much higher than for hydrogen or methanol derived from natural gas or biomass (see Figure 19-5). It is assumed, however, that by 2050 land-use constraints begin to limit the expansion of production of biomass-derived methanol and hydrogen in some areas, so that some electrolytic hydrogen enters the mix (see Figure 19-12 and Box 19-2).

19.3.1.4. Challenges Posed by Biomass Energy in the LESS Reference Cases

Several studies carried out in recent years suggest that "modernized biomass" could play a major role in the world's energy economy in the 21st century (see Box 19-3). Other long-term energy studies have ignored biomass; some that have not expect that biomass energy will evolve more slowly even if biomass energy is encouraged by public policies [for example, WEC's Ecologically Driven Scenario (WEC, 1993, 1994)].

The envisaged development of biomass energy is possible in principle. The assumed average biomass plantation yields—11 dry tons/hectare/year (dt/ha/y) in 2025, rising to 15 dt/ha/y in 2050 and 20 dt/ha/y, 2075-2100—though much higher than the yields for natural forests, are not unreasonable in light of experience with various cultivated crops (see Figure 19-3). Many studies indicate that these yields can be realized at the high net energy output/input ratios assumed for the LESS reference cases (see Section 19.2.5.2). Likewise, although the projected plantation areas are large (see Figure 19-11), even the 572 Mha targeted for the year 2100 in the BI variant is only 12% of the total amount of land in cropland plus permanent pasture (Hall *et al*., 1993). Yet concerns have been raised about the potential

Box 19-3. The Role of Biomass Energy in Some Recent Global Energy Studies

Five recent studies exploring alternative energy futures provide alternative views of the prospects for biomass energy:

- The World Energy Council projects (WEC, 1994) in its Current Policies Scenario for global energy that traditional (noncommercial) biomass energy use increases from 42 EJ in 1990 to 59 EJ in 2020 and that modern (commercial) biomass energy increases from 5 to 11 EJ. For the WEC Ecologically Driven Scenario (EDS), however, these totals for 2020 are 47 EJ and 25 EJ, respectively [compared to a total biomass energy use rate (all commercial) of 74 EJ/yr in 2025 for the BI variant of the LESS]; the projected 5.5%/yr growth rate for modern biomass energy use, 1990–2020, is regarded as a plausible but ambitious growth schedule, considering all of the new technologies involved and the institutional hurdles that must be overcome.
- Dessus *et al*. (1992) project total world biomass use as 135 EJ in 2020, of which 51% and 17%, respectively, are accounted for by commercial and noncommercial wood recovered from forests, 20% by biomass waste resources, and 12% by biomass crops grown on plantations. Dessus *et al*. (1992) apparently focus their expansion on biomass from forests because this large potential resource might be the most easily exploited potential biomass supply.
- The U.S. Environmental Protection Agency advances a scenario for a greenhouse-constrained world (Rapidly Changing World with Stabilizing Policies) in which the role of commercial biomass energy increases to 136 EJ by 2025 and to 215 EJ by 2050 (Lashof and Tirpak, 1990).
- In their Renewables-Intensive Global Energy Scenario (RIGES), Johansson *et al*. (1993a) project the biomass contribution (all commercial) to be 145 EJ by 2025 and 206 EJ by 2050; plantations account for 55–62% of the total, while forests account for only 5–7%. In the RIGES, the use of modernized biomass was projected to grow rapidly (10%/yr, 1990–2025) because of the multiple benefits it offers.
- In its 1994 long-term global energy scenario exercise, the Shell International Petroleum Company developed a "Sustained Growth" scenario in which it projects that by 2050—as in the BI variant of the LESS—more than half of total world primary energy comes from renewable energy sources. (The projected overall level of renewable energy development is twice the level in the BI variant of the LESS, however, because the overall projected level of energy demand is about twice as high at that time.) In this scenario, the overall contribution from biomass in 2050 is about 15% higher than in the BI variant of the LESS, although about 30% of total biomass in the Shell scenario is for noncommercial uses (Kassler, 1994).

conflict with food production, especially in developing regions (see Section 19.2.5.2 and Chapter 25).

If agricultural production can be modernized and intensified in environmentally acceptable ways, however, large increases in cropland probably will not be needed for food production (e.g., Waggoner, 1994; Smil, 1994). Indeed, low-cost bioenergy could attract industry to rural areas to provide the income growth needed to modernize agriculture (see Section 19.2.5.2). Preliminary analyses indicate good prospects in Brazil for large-scale development of bioenergy plantations without serious competition from food production (Carpentieri *et al*., 1993). Even in densely populated India, it has been suggested that some 60–70 million hectares of degraded lands might be good for energy plantations. In India, the potential conflict with food production is not expected to be great. Between 1970 and 1990, food production per capita increased while the total land area under cultivation stayed about the same, despite a 60% growth in population. Also, there are good prospects for substantial further gains in food crop yields (Ravindranath and Hall, 1994). Moreover, a preliminary country-by-country analysis exploring the potential for biomass energy production in the context of future food requirements in the developing world projects that there could reasonably be considerable amounts of land committed to biomass energy production in Africa, Asia, and Latin America without posing major conflicts with food production in the period to the year 2025 (Larson *et al*., 1995). Further investigations of these issues are needed, however.

19.3.1.5. Natural Gas-Intensive Variant of a LESS

The natural gas-intensive (NGI) variant of the LESS constructions (see Figure 19-8) is based on the following assumptions:

- Remaining recoverable natural gas resources are substantially higher than in the reference cases.
- All of the natural gas in excess of that for the references cases is used to make methanol and hydrogen. These displace methanol and hydrogen that would otherwise be produced from plantation biomass in the BI variant to the extent that this is feasible at the higher production levels of natural gas.
- Hydrogen production for this extra natural gas is carried out near depleted natural gas fields, so the stream of CO_2 recovered at the hydrogen production facility can be sequestered there (see Figure 19-5).
- The energy demand levels and structures are the same as for the BI variant.
- Except for the shift from biomass to natural gas for the production of methanol and hydrogen, the energy supply mix is the same as for the BI variant.

In this variant, remaining, ultimately recoverable natural gas resources for the United States are assumed to be the same as in the reference cases. For other regions, the high natural gas resource estimates of Masters *et al*. (1994) are assumed. Thus, total remaining, ultimately recoverable natural gas resources as of 1993 are 17,400 EJ—nearly 40% higher than in the reference cases. As in the reference cases, it is assumed that 80% of these resources are used up by the year 2100. In this case, global natural gas production increases to a level 2.3 times the 1990 level by the year 2050 before global production declines at a constant exponential rate.

In this variant, natural gas would be less costly than in the reference cases, which would make it harder for fuels derived from plantation biomass to compete. In the NGI variant, there would be no plantations in 2025; plantation requirements would be only about 40% of those in the BI variant in 2050 and 75% of those in 2100 (see Figure 19-11).

Annual CO_2 emissions would fall to 2 Gt C/yr by the year 2100 (see Figure 19-9), and cumulative emissions between 1990 and 2100 would be 476 Gt C (see Figure 19-10)—only slightly more than in the reference cases. Cumulative requirements from 1990 to 2100 for sequestering the CO_2 recovered in hydrogen production would be nearly three times as large as in the reference cases (44 Gt C vs. 17 Gt C), but this is small compared with the sequestering capacity of natural gas fields that would be theoretically available by 2100 via natural gas extraction (see Section 19.2.3).

19.3.1.6. Coal-Intensive Variant

Another strategy for achieving deep reductions involves using coal and biomass for methanol and hydrogen production, along with sequestration of the CO_2 separated out at the synthetic fuel production facilities. This strategy is pursued in a way that emphasizes the use of coal relative to biomass, subject to the constraint that the overall level of annual CO_2 emissions is the same as for the NGI variant. It is assumed that for this coal-intensive (CI) variant, all characteristics of the variant other than for methanol and hydrogen production are identical to those for the BI variant (for example, reference-case assumptions about remaining natural gas resources).

The separated CO_2 might be sequestered in saline aquifers or in depleted oil and gas fields (Williams, 1996). Because the cost of the coal or biomass contributes such a small amount to the overall cost of making hydrogen (see Figure 19-5) or methanol (Williams *et al*., 1995a, 1995b), it would not change the overall economics very much to ship the coal or biomass to a depleted natural gas field site for processing.

This variant offers considerably greater potential for reducing dependence on biomass than is feasible for the NGI variant (see Figure 19-11) because of the specification that CO_2 recovered at hydrogen and methanol conversion facilities be sequestered for biomass as well as coal feedstocks. Costs would be slightly higher because of the added complications of sequestering CO_2 recovered at coal and biomass fuel-processing facilities, but costs for demanded energy services could plausibly still qualify as being approximately the same as estimated future costs for current conventional energy (see Figure 19-6).

Cumulative sequestering requirements for this variant from 1990 to 2100 would be 145 Gt C (see Figure 19-10).

In this variant, global coal use would increase 47% by 2075, followed by a slow decline. Coal use in 2100 would be 31% higher than in 1990.

Two important lessons are highlighted by this variant. First, the production of hydrogen-rich fuels for fuel-cell applications allows coal to have a significant role as an energy source in a GHG-constrained world. Second, in this strategy, coal and biomass play complementary roles. Having some biomass in the energy system allows greater use of coal because for biomass grown on a sustainable basis with sequestration of the CO_2 separated at the conversion facilities, net life-cycle CO_2 emissions are negative (see Figure 19-5).

It is noteworthy that ongoing efforts to commercialize oxygen-blown coal gasifiers for integrated coal gasification/combined cycle power generation help to realize this strategy because the same kind of gasifier is needed for the production of methanol and hydrogen from coal.

19.3.1.7. High-Demand Variant

The LESS reference cases involve a high degree of decoupling of energy demand from economic growth for the entire period to the end of the next century. By 2100, primary energy demand doubles, compared to a quadrupling of energy demand in IPCC's IS92a scenario. The high-demand (HD) variant explores the potential for achieving deep reductions in emissions if energy demand and economic growth follow historical trends in the period beyond 2025. Overall demand for fuels used directly and for electricity are equal to those for the reference cases through the year 2025 but rise thereafter at constant exponential rates to the demand levels for the IS92a scenario by the year 2100. The energy supply base, to which are added the supplies for additional electricity and fuels used directly, is that for the NGI variant.

The major challenge of the HD variant is providing the extra fuels used directly with low emissions. The extra electricity might be provided entirely by some mix of intermittent renewable and nuclear electric sources, so that incremental power generation would pose no CO_2 management problems. To illustrate the possibilities, the HD variant is constructed with all of the incremental electricity provided by intermittent renewables. In principle, all of the incremental power could be provided from these sources. All incremental power requirements would come after the year 2050, by which time storage technology would plausibly be widely available to shape the output of intermittent resources to meet most electrical demand profiles. Also, there do not appear to be physical limits on intermittent resources at these generation levels, although power plant siting constraints in this time frame might limit additional capacity mainly to distributed photovoltaic systems and remotely sited, central-station, renewable electric power plants (Williams, 1995a).

All incremental requirements for fuel used directly are provided by hydrogen derived by thermochemical means from natural gas, biomass, and coal (see Figure 19-12), with sequestering of the CO_2 recovered at the fuel-conversion plants. By 2050 and beyond, the HD variant uses as much primary biomass energy as in the BI variant and as much natural gas as in the NGI variant. The extent of sequestration is dictated by a requirement that annual CO_2 emissions not exceed those for the NGI variant (see Figure 19-9).

Coal use increases 5-fold between 1990 and 2100 (see Figure 19-8); annual sequestration requirements increase from 0 in 2025 to 2.0 Gt C/yr in 2050 and 11.6 Gt C/yr in 2100. Cumulative sequestration requirements from 1990 to 2100 amount to 321 Gt C. In principle, sequestering might be accomplished entirely in natural gas fields until the year 2100 (Williams, 1995a). However, additional secure storage capacity would be needed to continue sequestering CO_2 at high rates and to maintain low emissions levels with continued intensive use of coal well beyond the year 2100.

The achievement of low emissions in this variant appears to be feasible. There would be much less flexibility, however, to choose among alternative options for achieving deep reductions at the high energy-demand levels of the HD variant than under reference-case energy-demand conditions. This exercise underscores the importance of energy efficiency in achieving deep reductions in GHG emissions.

19.3.2. A Top-Down Construction of a LESS

To test the robustness of the bottom-up energy supply analysis indicating that deep reductions in CO_2 emissions could be realized by 2100, a top-down global energy modeling analysis also was carried out for the Working Group (Edmonds *et al.*, 1994), incorporating performance and cost parameters for some of the key energy technologies used in the construction of the BI variant of the reference cases. Six technology cases were modeled using this top-down approach. The trajectories of global energy and the corresponding CO_2 emissions are shown in Figure 19-15.

The Edmonds-Reilly-Barns (ERB) model used here comprises four modules: demand, supply, energy balance, and GHG emissions. The first two modules determine the supply and demand for each of six major primary energy categories in each of nine global regions. The energy balance module ensures model equilibrium in each global fuel market, based on assumptions regarding resources and fuel technologies. The final module calculates energy-related emissions of CO_2. Demand for each fuel is determined by population; labor productivity; energy end-use intensity; energy prices; and energy taxes, subsidies, and tariffs. Energy end-use intensity is a time-dependent index of energy productivity. Demand for energy services in each

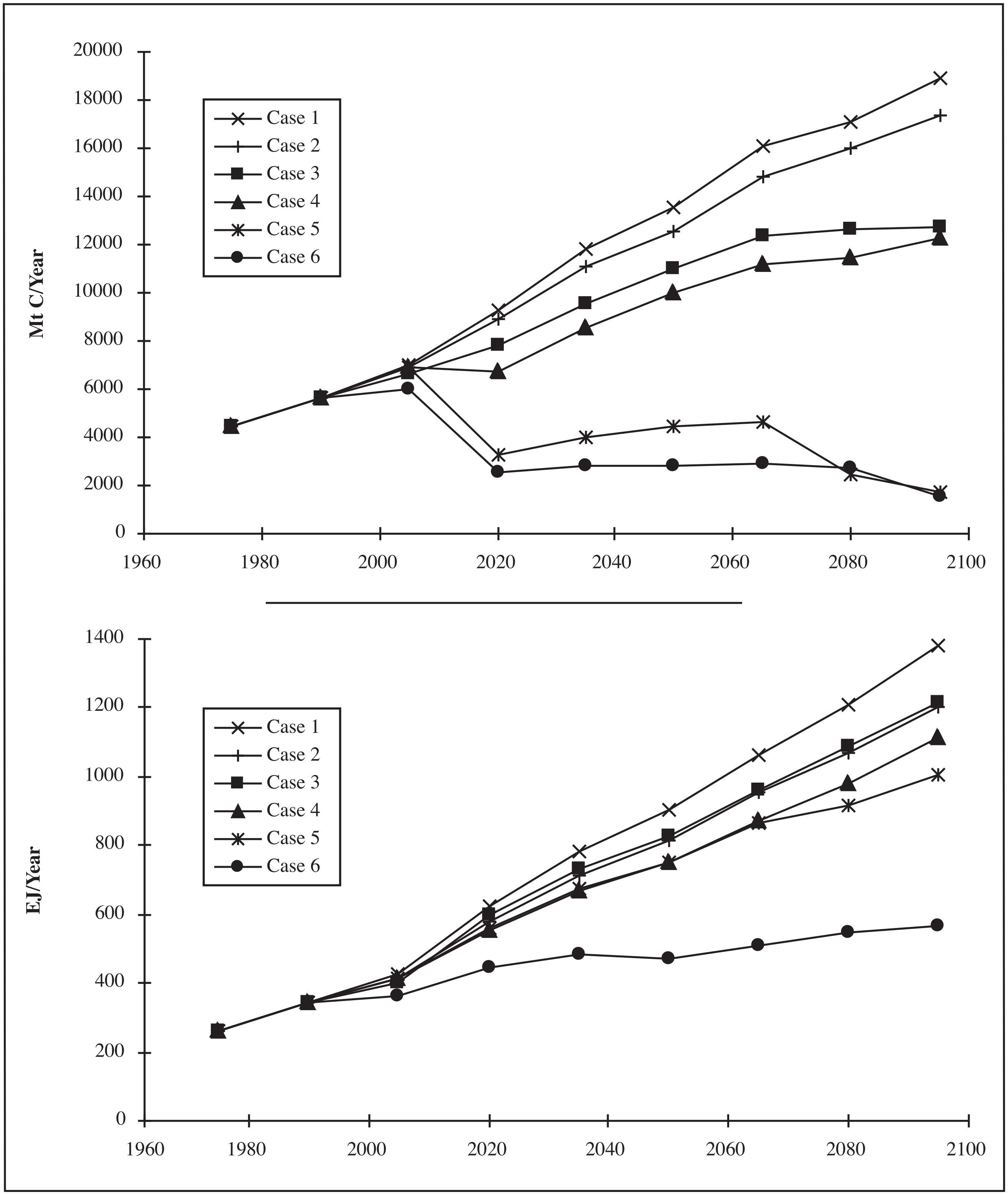


Figure 19-15: Global annual CO_2 emissions from fossil fuel burning (top) and global annual primary energy production and use (bottom) for six alternative cases constructed by Edmonds *et al*. (1994) in a "top-down" modeling exercise aimed at constructing a LESS. Case 1 is the reference scenario, with features very similar to the IPCC IS92a scenario; the exogenous end-use energy intensity improvement rate is 0.5%/yr by 2005, rising to 1%/yr by 2035, and reaching 1.5%/yr by 2065. Case 2 emphasizes energy-efficient power generation from fossil fuels (with efficiencies reaching 66% by 2095), but is otherwise like Case 1. In Case 3, liquefied hydrogen from natural gas, biomass, and electrolytic sources is used in fuel cells for transportation, and solar and wind power become highly competitive. Case 4 is like Case 3 except that compressed hydrogen is used instead of liquefied hydrogen. Case 5 is like Case 4, except that biomass prices are more competitive. Case 6 is like Case 5, except that the exogenous energy end-use intensity improvement rate reaches 2%/yr by 2050.

region's end-use sectors is determined by the cost of providing these services, and by income and population. For OECD regions, energy demand is disaggregated into residential/commercial, industrial, and transportation sectors. Energy supply is disaggregated into renewable and nonrenewable sources. Fossil fuel energy supplies are related to the resource base by grade of the resource, cost of production, and historic production capacity. The rate of technological change on the supply side varies by fuel. The energy balance module chooses energy prices that bring demand and supply into balance, given technological assumptions.

The point of departure for the top-down analysis is a scenario (case 1) that is very similar to IPCC's 1992 IS92a scenario (the same overall levels of population growth, GDP growth, primary energy use, CO_2 emissions, etc.). Five alternative technology cases were then modeled, each incorporating successively more of the characteristics of the technologies assumed for the construction of the BI variant of the reference case.

Two of the options (cases 5 and 6) are characterized by about the same level of CO_2 emissions as the LESS reference case in 2100 [compare Figure 19-15 (top) with Figure 19-9], even though their primary energy-use levels at that time are very different: For case 5 it is 40% higher than for the LESS reference case, and for case 6 it is 20% lower. These energy balances are arrived at with natural gas prices increasing to $8–10/GJ, oil prices increasing to $10–15/GJ, and coal prices increasing to $2–3/GJ by 2100.

All six cases have about the same level of exogenously defined global GDP in 2100 (although global GDP is slightly higher for cases 5 and 6 than for case 1). This shows that if the assumed technological characteristics are realized, deep reductions could be achieved without economic penalty. What is needed is a technology policy that facilitates the development and commercialization of GHG-friendly technologies that offer the potential at maturity of being competitive under market conditions with fossil fuel technologies.

This important result shows that the large differences in outcomes often observed between top-down and bottom-up modeling exercises are not due to irreconcilable differences between these very different approaches, as some have suggested, but rather to differences in assumptions.

19.3.3. Concluding Remarks

Costs for energy services in each LESS variant relative to costs for conventional energy depend on relative future energy prices, which are uncertain within a wide range, and on the performance and cost characteristics assumed for alternative technologies. However, within the wide range of future energy prices, one or more of the variants would plausibly be capable of providing the demanded energy services at estimated costs that are approximately the same as estimated future costs for current conventional energy. In a LESS scenario, substantial reductions in CO_2 emissions would result from the deployment of advanced energy supply technologies, along with more efficient energy-using equipment. Such outcomes appear to be possible given adequate time (several decades) and an economic climate and public- and private-sector policies conducive to the needed innovations. Strong and sustained investments would be needed for research and development, demonstration, and diffusion of energy technologies characterized by low or zero CO_2 emissions; at present, the levels of investment in such activities are low and declining (see Section 19.4).

The LESS constructions show that with modest rather than steep energy demand growth, deep reductions in emissions could plausibly be achieved with a variety of mixes of low-carbon fossil fuels, decarbonized fuels, renewable energy sources, and nuclear energy. Thus, society would not have to pursue all options but would have the flexibility to choose mixes of GHG-friendly technologies based largely on their effects on the local and regional environment, energy security, developmental benefits, and cost. Moreover, society could shift course to a different path if, for unforeseen reasons, an initial choice proved to be problematic or if more attractive options emerged as a result of unexpected technological innovations. Less flexibility would be possible at high levels of energy demand.

Finally, it is hoped that these LESS constructions will encourage others to explore in more detail the advantages and drawbacks of the options described here and to identify and articulate other paths to an energy future characterized by low emissions of CO_2.

19.4. Implementation Issues

The preceding section identified technology options that together could make significant reductions in long-term GHG emissions with projected costs to society of energy services that are approximately the same as estimated future costs for current conventional energy. The ability of any of these technologies to realize its potential depends on the rate and extent of its adoption under widely differing institutional, economic, and natural-resource constraints in various countries and regions. This section briefly addresses some of the associated implementation issues.

A transition to renewable and other low-CO_2-emitting energy technologies is not likely to occur at the pace envisioned under business-as-usual conditions. A variety of problems inhibit their development and deployment. For example, private companies are unlikely to make the investments necessary to develop renewable technologies at a rapid rate because the benefits are distant and not easily captured by individual firms; they also will not invest in large volumes of commercially available technologies to the extent justified by the external benefits (for example, reduced emissions). Also, conventional energy technologies benefit from direct subsidies of more than $300 billion per year worldwide (Koplow, 1993; OECD, 1992; IEA, 1993b; Larsen and Shah, 1994).

Actions conducive to a transition to an energy system based on low CO_2-emitting energy technologies should include policy changes that address seven key areas: energy system planning; financing; technology research and development; technology transfer, adaptation, and deployment; local environmental impacts; capacity building; and institutional arrangements (UNSEGED, 1992; WEC, 1994; Johansson *et al*., 1993a; UNCNRSEED, 1994, 1995).

Economic instruments such as tradable emissions permits and emissions fees (taxes) could be designed to partly incorporate the true social and environmental cost of existing technologies in the price of the energy that they produce (IEA, 1993b). Others, such as temporary subsidies, could help accelerate the development and implementation of new technologies.

Regulations—defined as legislation or government or private-sector rules (supported by sanctions)—can be designed to influence public and private decisionmakers in their transactions. Regulations might focus on technology performance, influence the use of technology (for example, use of electricity-dispatch rules to prioritize low-emitting technologies), or promote the training of operating personnel through licensing arrangements. Particularly important in the power sector are rules that determine if and under what terms small, independent producers of renewable electricity (including intermittent generation) may gain access to the utility grid. For biomass energy, agricultural, forestry, and land-use policies are important.

For example, in the United States, an effective regulatory instrument—the Public Utilities Regulatory Policy Act (PURPA) in 1978—led to the creation of a competitive, decentralized market. PURPA required electric utilities to buy power from independent producers at the long-term avoided cost. This law is largely responsible for the introduction of 8,000 MW_e from biomass, 1,500 MW_e from wind, 730 MW_e from small-scale hydropower, and 350 MW_e from solar thermal-electric technology (WEC, 1994).

There is a worldwide trend toward increasing competition in the power sector. This will generally be helpful to small, high-efficiency, and more economical cogeneration systems, while discouraging large, less-efficient, and less-economical stand-alone steam turbine-based power plants. On the other hand, this trend will reduce interest in the long term and the measures that need to be taken to bring new technologies to the market.

Research and Development (R&D): High rates of innovation in the energy sector would be needed to realize any of the LESS constructions. The trend in recent years, however, has been declining investment in energy R&D on the part of both the private sector (Williams, 1995b) and the public sector (see Table 19-9). Over the last decade, public-sector support for energy R&D has declined absolutely by one-third and by half as a percentage of GDP. Moreover, government-supported R&D has generally focused on nonrenewable energy technologies. Less than 10% of IEA member governments' support is for renewable energy technologies.

It is important to have a government energy R&D strategy that does not attempt to pick winners. Fortunately, many of the promising technologies for reducing emissions, such as fuel cells and most renewable energy technologies, require relatively modest investments in R&D. This is a reflection largely of the small scale and modularity of these technologies and the fact that they are generally clean and safe (Williams, 1995b). As a result, it should be feasible, even with limited resources for R&D, to support a diversified portfolio of options. It has been estimated that research and development of a range of renewable energy technologies would require on the order of $10 billion (WEC, 1994).

Table 19-9: *Total reported IEA government R&D budgets (columns 1–7; US$ billion at 1994 prices and exchange rates) and GDP (column 8; US$ trillion at 1993 prices).*

Year	(1) Fossil Energy	(2) Nuclear Fission	(3) Nuclear Fusion	(4) Energy Conservation	(5) Renewable Energy	(6) Other	(7) Total	(8) GDP	(9) % of GDP
1983	1.70	6.38	1.43	0.79	1.05	1.08	12.40	10.68	0.12
1984	1.60	6.12	1.44	0.70	1.02	0.99	11.88	11.20	0.11
1985	1.51	6.26	1.42	0.70	0.85	1.04	11.77	11.58	0.10
1986	1.51	5.72	1.31	0.59	0.66	0.94	10.74	11.90	0.09
1987	1.37	4.36	1.23	0.65	0.62	1.04	9.27	12.29	0.08
1988	1.46	3.64	1.13	0.53	0.62	1.19	8.58	12.82	0.07
1989	1.30	4.42	1.07	0.45	0.57	1.33	9.13	13.23	0.07
1990	1.75	4.48	1.09	0.55	0.61	1.15	9.62	13.52	0.07
1991	1.52	4.45	0.99	0.59	0.64	1.39	9.57	13.58	0.07
1992	1.07	3.90	0.96	0.56	0.70	1.28	8.48	13.82	0.06
1993	1.07	3.81	1.05	0.65	0.71	1.38	8.66		
1994	0.98	3.74	1.05	0.94	0.70	1.30	8.72		

Sources: Government energy R&D expenditure data are from IEA (1995); GDP data are from OECD (1994).

Demonstration and Commercialization: R&D programs are necessary but not sufficient to establish new technologies in the marketplace. Commercial demonstration projects and programs to stimulate markets for new technologies also are needed. For a wide range of small-scale, modular technologies—including most renewable energy technologies and fuel cells—energy production costs can be expected to decline with the cumulative volume of production, as a result of "learning by doing" (Williams and Terzian, 1993; WEC, 1994).

The World Energy Council estimates that subsidies on the order of $7–12 billion are needed to support initial deployment of various renewable energy technologies until manufacturing economies of scale are achieved, to compete with conventional options (WEC, 1994). Thus, the World Energy Council estimates that the total investment needed for R&D on and support of initial deployment of renewables to be $15–20 billion. This is 0.1% of the annual global gross national product at the turn of the century and would, of course, be distributed over a couple of decades (WEC, 1994).

Information is a commodity that is especially subject to problems of market failure. One important area for government action is resource evaluation. Unfortunately, sufficiently detailed resource evaluations to facilitate investments are unlikely to be carried out by the private sector. Investigations of a wide range of potentially recoverable renewable resources, especially wind resources and land for energy plantations, would help reduce investment risks considerably (Johansson *et al*., 1993a; UNCNRSEED, 1994).

In several countries, government encouragement of development and commercialization has been successful in introducing new energy supply technologies in national or regional markets—for example, wind energy in Denmark (Sørensen *et al*., 1994); grid-connected cogeneration and renewable electric systems in the United States and home-scale photovoltaic systems in Indonesia (WEC, 1994); a sugar cane-based ethanol industry in Brazil (Goldemberg *et al*., 1993); and a nuclear energy industry in France (Souviron, 1994).

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